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NON-CONVENTIONAL ENERGY SUPPLIES AND MARKET FAILURE: THE CASE OF COAL LIQUEFACTION IN ALBERTA

by

DUNCAN KNOWLER

(C)

A THESIS

SUBMITTED TO THE FACULTY OF GRADUATE STUDIES AND RESEARCH

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Abstract

Synthetic crude oil produced from non-conventional sources, such as tar sands or coal conversion, has been the focus of much analysis. Unfortunately, most evaluations of non-conventional energy projects have dealt with technical aspects and private cost viability. This thesis has attempted to assess the prospects for coal liquefaction from a social perspective and to determine whether private incentives to undertake liquefaction are in line with social desirability. This latter objective involved assessing overall private profitability as well as whether a private firm would choose the socially optimal input-mix. Where private incentives diverged from social viability, it was assumed that market failure existed.

The four liquefaction projects examined were based on information contained in an engineering feasibility study and data from other sources, and were assumed to come on-stream in 1991. Each project produced 60,815 barrels per day of a 29.5° API synthetic crude from an identical advanced German liquefaction technology. Differences between projects involved the manner in which power and hydrogen for conversion were supplied.

Rather than use the net present value criterion for comparing projects, this parameter was set equal to zero and the real annual increment in imported oil prices which satisfied the net present value equation was calculated. This was meant to circumvent the uncertainty associated with

future oil price inflation. Thus, results are not contingent on any particular price scenario occurring during the project life. In order to account for potential changes in oil prices and provincial economic activity between 1982 and 1991, three scenarios were developed for the real 1991 oil price. As well, the possibility of cost overruns was taken into account by including a scenario with capital costs at 82 percent above their base case values based on research by the Rand Corporation on pioneer processing plants.

Results of the analysis indicate that if current capital cost estimates are accurate and real increases in oil prices over the next several decades can be expected in the 2 percent per year range, coal liquefaction could present a viable alternative to imported oil. Also indicated is the possibility that, should liquefaction be socially viable, a private firm may not be willing to undertake it; and even if it is pursued, an inappropriate process design would be selected. Where capital cost overruns are significant and the power of OPEC to sustain real price inflation in oil prices is eroded, coal liquefaction is unlikely to be a viable alternative import substitute.

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1. Introduction

1.1 Problem and Approach

The notion that Canada should be aggressively pursuing self-sufficiency in petroleum has received widespread attention in recent years. Continued importation of oil, it is argued, maintains dependence on uncertain supplies of a crucial commodity as well as affecting the balance of trade in an unfavorable manner (Berkowitz, 1981). Aside from measures aimed at conservation, discussion has focused on the efficacy of substituting domestic production for imports. This import substitution could originate from a number of alternative sources. These include increased production of conventional petroleum from enhanced recovery and frontier areas, and synthetic oil from non-conventional sources such as tar sands and coal. It is the non-conventional option which presents perhaps the greatest long run potential. Although tar sands development has been vigorously studied and promoted, oil from coal, or coal liquefaction, has received minimal attention. This is due to the seemingly lower private production costs of syncrude from tar sands (Dynawest, 1983). Despite this, a full accounting of all social benefits and costs of the two alternatives has not been made and there is some evidence to suggest that liquefaction may appear relatively more attractive from this perspective (Dynawest, 1983).

Technically, coal conversion can be described as a means of upgrading coal to a higher quality liquid fuel by adding hydrogen under conditions of high temperature and pressure and usually in the presence of a catalyst. Present research centers around optimal use of catalysts, temperatures, and pressures, as well as scale-up to mega-project commercial size. Liquefaction is a well-established chemical procedure dating back commercially to pre-war Germany.

Despite some technical and political considerations, the argument over import substitution, whether from coal liquefaction or other sources, is largely one of the economics of market failure. Obviously, if a perfectly operating market for petroleum existed, import substitution would be simply a matter for domestic costs versus import costs. Domestic production, both conventional and non-conventional, would take place up to a point where the marginal supply cost was equal to the import charge, assuming sufficient demand existed.

In reality, such a perfectly operating market does not exist. The simple market solution based on private costs will be prevented in the presence of any of the following market distortions: "monopoly power, price or quantity controls, taxes and subsidies, external effects and other market imperfections" (Treasury Board, 1976, 13). The argument over import substitution revolves, in part, over the existence and degree of these distorting factors.

If it were agreed that market distortions did exist, then one could envisage them leading to one of the following possible situations (Little and Mirrlees, 1974):

1. a project may be viable and optimal from both a private and social perspective, despite any market failure;
2. a project, due to market distortions, may be viable and optimal from a private but not a social perspective;
3. a project, again due to market distortion, may be viable and optimal from a social but not a private perspective;
4. a project may be neither viable nor optimal from either perspective regardless of distorting factors.

The first and last situations do not present any allocation problems and can be effectively disregarded. The second circumstance, private but not social viability, is relevant in certain areas of project analysis. However, with regard to import substitution and nonconventional energy projects, it is the third situation which proves most interesting. It is in this case, where social returns are greater than private returns, that economic theory advises some form of corrective action such as subsidies to bring market returns in line with social desirability. In fact, President Carter's 1979 program to encourage development of an American synfuels industry through establishment of the Synthetic Fuels Corporation is a prime example of such a measure.

Analysis of coal liquefaction, as an import substitute, lends itself well to the market distortion perspective

suggested above. A divergence between private and social desirability may occur with respect to two issues: the overall profitability of liquefaction, and thus the rate of industry development, and the choice of technology or design parameters to produce a given output of syncrude. In the former case, social returns to liquefaction must be compared to the on-going costs of oil importation. Where these social returns justify pursuit of a liquefaction alternative, private returns will indicate whether a private firm would be willing to undertake such a project. If these latter returns are insufficient to induce production, market failure would appear to be evident.

With regard to choice of technology, a similar argument applies. The numerous liquefaction processes available suggest a wide range of potential private and social costs. But 'technology' is not used here in this sense; rather, the reference is to the various design or input-mixes which are possible under the auspices of any one process. This involves choice of hydrogen production technique, power source, and use of by-products. Where there is a divergence between private and social evaluations, particularly with regard to input and associated by-product prices, the potential for an inappropriate choice of process design exists.

Since development of a commercial-scale liquefaction facility would require at least 8 to 10 years lead time, the policy implications of market failure may be significant.

Research and development focusing on a non-conventional energy source which does not provide net social benefits, or on a process design which is non-optimal, may have large social cost implications. Thus the need for analysis of potential policy options at an early stage of development is apparent.

Based on the above discussion, the objectives of this thesis can be reduced to the following two questions:

1. Is liquefaction a likely candidate for development on its own merits (not vis-a-vis other substitutes) and if so, would a private firm be willing to undertake it?
2. Of the various design or input-mixes available, which option is socially optimal, and would a private firm make this choice?

In order to perform any sort of benefit-cost or financial analysis calculations, a reliable source of cost data must be found. Fortunately, research work co-sponsored by Algas Resources Ltd. (now Noval Technologies Ltd); Alberta Energy and Natural Resources; and the federal Energy, Mines, and Resources department was made available for the analysis here. This work comprised a comprehensive mid-phase study of the technical and economic feasibility of coal liquefaction in Alberta. The study, entitled Coal Liquefaction Plant Feasibility Study (Kilborn Alberta Ltd., 1981), is an engineering analysis and, as such, includes basic cost and technical data as well as preliminary cash-flow and rate of return information.

Analysis in the Algas study involved two alternatives, each using natural gas as a hydrogen source but differing in their power supply configurations. Based on technical and economic studies done elsewhere, it was decided for this study that other alternatives involving gasified coal as a hydrogen feedstock, rather than natural gas, should be included. As a result, four alternatives are analysed here based on different hydrogen feedstocks and power sources.

Costs for the two additional alternatives are developed from American data making use of the methodology from the Algas study. The cost of coal is estimated separately based on the differing volumes required for each alternative.

In order to determine the potential for liquefaction from a social perspective, benefit-cost analysis is applied to the four alternatives using social rather than private costs. Since future increases in oil prices are so uncertain, the real rate of increase in current prices is taken as the choice variable rather than the project's net present value, which is set equal to zero. Solving for this parameter gives a 'required' average annual real increase in the output price which represents a minimum value in order for the project to be socially viable. These required rates of increase for each project can then be compared to historical averages and forecast rates as well as to those for the other four alternatives.

For comparison, a financial or market analysis is done on the same four alternatives using the same breakeven or

required oil price approach but with market prices and private discount rates used instead. Results from the two forms of analysis are compared and discussed and a case made for the existence of market failure. Following this, the implications of the analysis are examined in terms of potential social losses and public policy, especially with regard to research and development.

1.2 Scope and Outline

There exists a wide array of complex issues concerning import-substitution and the role coal conversion could play. In order to limit the study to reasonable bounds, a number of factors are not discussed at length. The suitability of liquefaction vis-a-vis other substitutes (tar sands, frontier production, and enhanced recovery) is not explored in detail. The analysis also abstracts from questions of income distribution and equity, concentrating instead on efficiency considerations.

In addition, extensive discussion of the coal and petroleum industries is not included. The plains coal industry centers primarily around power generation where utility companies hold a lease and hire a contractor to mine the coal. The relevance of this industry, outside of competition with liquefaction for coal, is limited. The oil industry is more likely to be involved in liquefaction. Esso Resources, for example, are examining the Judy Creek area as a potential liquefaction site (Jones, pers. comm.). Where

relevant, the oil industry is discussed in the text.

The thesis is structured in the following manner. Chapter 2 presents a literature review of import substitution and the arguments for market failure with regard to this activity. Chapter 3 briefly reviews the historical and technical background to liquefaction as well as presenting the cost estimates for the alternatives examined. Chapter 4 first discusses a number of economic considerations in analysing liquefaction and then proceeds with the development and application of an algorithm for social assessment of a liquefaction project. Chapter 5 uses a similar approach but maintains the perspective of a private firm in performing a financial or market price analysis. Chapter 6 discusses the implications of the study. The final chapter summarizes observations and results and presents the conclusions of the thesis. Detailed cost estimates and statistical manipulations are contained in appendices.

2. The Economics of Import Substitution Using Non-conventional Energy Sources

2.1 Introduction

This chapter reviews the theory and evidence on market failure in the market for non-conventional energy, with special reference to synthetic oil sources. As previously suggested, there is significant polarization over the notion of whether the paucity of non-conventional energy projects results from a lack of appropriate market incentives or whether, instead, this arises from accurate market signals which simply reflect poor social profitability. Specific distortions which are most often mentioned in association with non-conventional energy are the following: inappropriate pricing polices, discrepancies between private and social discount rates, regulatory uncertainty, and non-appropriable benefits and costs. Whether these lead to a misallocation of resources and whether some form of corrective policy is in order to encourage import substitution may depend on several factors besides the mere presence of such distortions. We turn now to a discussion of the qualitative nature of possible distortions and the results of relevant empirical work.

2.2 Pricing

Despite the fact that viewpoints on promoting import substitution fall into two camps, either vigorously supporting subsidization due to the unique problems of synthetic fuel development, or advocating treatment similar to that accorded to any generally competitive industry, there is almost uniform agreement among economists that the domestic oil price should move to world levels. In a sense, as Joskow and Pindyck (1979) point out, world price for oil would represent a non-structural solution to excess demand; rising prices would reduce quantities demanded and encourage expanded production.

In fact, a world price received for domestic production might remove a perceived need for subsidies in two ways. First, there is the simple notion that a higher price may mean projects seen as being socially profitable while privately not so, will now become feasible from both perspectives. This would remove any concern over subsidies since they presumably would not be needed. A second notion is that private companies, in receiving world price for conventional production, would have much larger cashflows from which to draw for the financing of non-conventional, capital-intensive projects. This would alleviate two potential distortions associated with financing large projects: the difficulties associated with the sheer magnitude of financing, including associated risk; and the uncertainty associated with government participation in

financing which these sheer magnitudes often necessitate. Donner argues this latter point when he states:

> The problem with large project financing is that government involvement, although necessary, tends to inhibit the attraction of private capital because it sets up a completely new level of risk for investors. (Donner, 1982, 59).

Another area of concern is the particular method by which prices are regulated, a point mentioned by Joskow and Pindyck (1979) and applied to the Canadian scene by Wirick (1982). Governments, in order to prevent the possibility of windfall profits should large unexpected price increases occur, have developed 'formulas' which average historical prices or create a ceiling for unit returns but not a compensating floor below which prices will not be allowed to fall.

It is this sort of spirit which pervades the Federal and Alberta Governments' pricing agreement of 1981. Outlined in this agreement is a formula for the synthetic fuel price or New Oil Reference Price (NORP). The effect of this pricing scheme is the following:

> If depressed markets force world oil prices well below the NORP, then the hypothetical megaproject returns fall accordingly. On the other hand, if tight market conditions drive international prices well above the NORP, domestic returns rise only at the level of a (one-quarter lagged) two-year moving average - still subject to the price ceiling of the current actual world price. This means that if a temporary shock for a limited time drives world oil prices sharply above the NORP, producer returns may never fully reflect these buoyant market conditions. (Wirick, 1982, 545)

With the upside profit potential capped and the downside risk left open, expected returns from such projects are

necessarily lower and some marginal projects may be inappropriately discarded.

More relevant to the case of liquefaction is the pricing of certain inputs and associated co-products. Due to the technical nature of coal liquefaction, hydrogen requirements can be met in several ways: through steam reforming of natural gas or via gasification of a coal-like residue which remains after liquefaction. Natural gas could be expected to be available at the domestic price which is approximately 40 to 60 percent of the export price, depending on the export value chosen. Although use of effectively subsidized natural gas may in part compensate for a regulated price on product output, there may be implications from this regarding the socially optimal technology. If current price signals encourage a wrong choice, social costs will ensue despite apparent private and social viability. This topic is developed at length in later chapters.

An additional consideration with liquefaction is the possibility for co-production of power. The large quantities of solid process residue and fuel gas produced as by-products of liquefaction are potential feedstocks for fossil fuel-fired power generation. Incremental construction costs associated with producing power from a liquefaction facility are lower than costs for stand-alone plants. The social benefits of this power would be the cost advantage of the liquefaction site over marginal costs for new facilities

elsewhere. Where the regulation of electricity prices results in received-prices well below provincial grid marginal costs, incentives for such 'co-generation' outside the provincial grid may be lacking. Such a pricing situation can be maintained because a public utility has the ability to offset losses from higher-cost plants with rent from the lower-cost facilities; a stand-alone liquefaction plant exporting power, even with marginal costs lower than those of the public utilities, could not do this.

2.3 Discount Rates

Distortions in capital markets, through their impact on discount rates, have also been argued to limit the allocation of resources to non-conventional energy projects. The case for this proceeds as follows; certain imperfections in the capital market are said to lead to the private discount rate being higher than the social rate resulting in construction of a suboptimal number of capital-intensive projects. For such projects, the small proportion of cost as ongoing operating expenses means that the present value of costs will decrease by a smaller magnitude than the present value of revenue, as the discount rate is increased. It is possible then that some capital-intensive projects, although socially profitable, may not meet private rate requirements where the private rate is too high. The question then becomes one of whether the rate is unjustifiably high relative to the social rate.

Although a number of factors are often mentioned to explain why private rates would be too high, two appear to be most relevant to the case of large energy projects. These are distortions arising from risk premiums and taxation. Risk is said to be lower in the public sector due to the ability of governments to spread risk over many projects as well as many individuals (Joskow and Pindyck, 1979). Private firms tend to have their risk more concentrated, leading them to expect higher returns as compensation for the greater range of possible outcomes. In fact, risk premiums in non-conventional energy investments appear to be very large. The desired real after-tax return for the Alsands project was 10.5 percent (Mariash, pers. comm.) compared to economy-wide rates in the order of 5 to 7 percent (Helliwell and May, 1976; Tarasofsky et al., 1981). It is not entirely valid, however, to compare a desired rate with historic rates, since desired rates will not always be realized.

Where risk premiums are very large it may be argued that some form of government assistance is appropriate. Joskow and Pindyck dispute this:

> If new energy technologies are inherently risky, there is little reason to believe that the government can make them any less so. Government only shifts risk from investors to taxpayers: it does not eliminate it. (Joskow and Pindyck, 1979, 171)

Thus, subsidies will not change the probability distribution of returns, only reduce the disutility arising from any particular return from the perspective of a private firm.

Concern over taxation focuses on the role of taxes as a 'wedge' between net-of-tax returns, upon which private investment decisions are made, and gross returns, which reflect the true opportunity cost of project capital to society. A dispute over the distortions created by taxation, in part, reduces to a discussion of which is the appropriate social discount rate, the time preference rate, approximated by the after-tax return on savings, or the opportunity cost of capital rate, approximated by the pre-tax return on marginal investments. This abstracts from issues such as intergenerational equity and risk which are also involved in the difference between discount rates.

It is often maintained that the proper discount rate for a public project will depend largely on the source of funds; personal income tax revenue would imply a time preference rate as most appropriate, since consumption is affected, while capital market borrowing would suggest the opportunity cost of funds approach due to its effect on investment (Mishan, 1976).

Joskow and Pindyck (1979), in discussing non-conventional energy, argue that the relevant rate for social purposes should be the gross-of-tax rate since capital "is withdrawn from the private sector, thereby losing returns from private investments that would otherwise have been made and losing tax revenue that such investments might have generated." (Joskow and Pindyck, 1979, 171). This seems plausible in terms of the use of funds but it remains

unclear as to which rate is appropriate for inter-temporal discounting of benefits and costs.

Besides creating a potential distortion merely from their existence, taxes could cause a further distortion if they become a component in the political-corporate bargaining process which precedes government approval of certain investment projects. For non-conventional energy projects this appears possible. Wirick, referring to the Canadian context, states:

> Ideally, governments should tax away only 'excess' returns (rent in formal economic terminology). Yet given the technical complexities of the megaprojects and the bargaining inherent in government-firm discussions, it is far from easy to establish what part is necessary return and what is economic rent. Companies will posture and threaten to cancel the development unless their revenue share is increased. The two governments (while pressuring each other for further concessions) will argue that returns are already adequate and will threaten to allow the project to collapse rather than acquiesce in 'unreasonable' demands. (Wirick, 1982, 545)

In addition, where excessive or inadequate taxation results in a divergence between pre-tax rankings of various projects' returns and after-tax rankings, project-by-project bargaining will lead to social costs.

Several observations emerge from our discussion of the discount rate issue. First, private firms wishing to engage in synthetic fuel production expect higher after-tax rates of return than average after-tax returns economy-wide. Presumably, this is a result of above-average risk levels experienced in non-conventional energy investments due to uncertain revenues arising from world oil market conditions

and government regulation, and uncertainty over actual final costs. Second, if taxes are negotiated on a project-by-project basis, private after-tax returns may not properly reflect social desirability where this is based on gross-of-tax returns since consistency among the pre- and post-tax rates of return for these projects may be lost. Finally, although the private rate may be higher than a social rate applied to the same project, it is unclear whether tax and risk factors justify this, and further, it is uncertain what social rate should be used in assessing the net social benefits of non-conventional energy.

2.4 Regulatory Uncertainty

Existing regulation, such as administered prices and environmental controls, has been discussed as a possible source of market imperfection inhibiting the optimal development of a synfuels industry. In addition to concerns over these current circumstances, uncertainty over future regulatory action may also represent a distortion. Before elaborating on this, however, it is necessary to distinguish between 'direct' uncertainty, where unknown future actions of governments result in risk, from situations of 'reflected' risk (Schmalensee, 1980). This latter term refers to cases where uncertainty originating elsewhere is passed on to government legislators. A prime example of this is uncertainty over future environmental regulations which exists because actual environmental effects are presently

unknown. This is discussed further in section 2.5.5.

Direct regulatory uncertainty arises primarily with respect to prices and as a result, profits. It has been argued that even if current prices were allowed to rise to world levels, there is no assurance that such a policy would continue into the future (Schmalensee, 1980). Non-conventional energy technologies, with their heavy front-end capital requirements, may be especially vulnerable to the vagaries of government pricing policy since production, once begun, must go on in order to recover any portion of sunk capital costs.

Wirick (1982) points out that the existence of price regulation and an uncertain world do not in themselves create a market distortion. This only occurs when either of two requirements are not met. The first is that prices, taxes, and royalties must be specified for each state of the world or level of world prices. Secondly, any agreement to such a schedule must be equally binding on all parties. Given these conditions, a socially optimal rate of industry development could occur in the absence of other distortions, although this would likely be lower than where such regulation did not exist if prices are set below their free market values. For Canada, the first condition is reasonably well satisfied by the energy pricing agreement of September 1981, although it only specifies prices until 1986. The second condition does not appear to hold for the Canadian case. The mere fact that a rewriting of this agreement seems

likely, based on a significant drop in the world price in early 1983, is sufficient to make this point.

Although subsidies might be the prescribed solution to a distortion such as regulatory uncertainty, it would be ironical if a firm was paid a subsidy to alleviate risk induced by the very source of subsidy funds. Instead a more logical step would be to eliminate the source of distortion through appropriately drawn up agreements which attempt to partition the nature of the risks involved, and to address each separately.

2.5 Non-appropriable Benefits and Costs

Discussion so far has centered around market distortions which affect the private profitability of non-conventional energy investments. In addition to these are possible non-appropriable benefits and costs. These accrue outside of a private accounting stance but represent part of socially relevant values. It is sometimes argued that these factors, for which a private firm does not receive or pay proper recompense, also require corrective action in the form of protective tariffs or government subsidies (Schmalensee, 1980). The efficacy of such action will depend on the degree to which these non-appropriable effects exist and whether internalizing them in the social evaluation of non-conventional energy investments represents the best means of dealing with such externalities.

2.5.1 Learning Effects

One of the major factors cited in arguments favoring subsidization of new energy technologies, especially initial projects, is the supposedly pervasive nature of learning effects that would be associated with commercialization. Learning effects, refer to a situation of falling long-run marginal unit costs as cumulative industry output rises. These effects, which are dynamic and industry-wide in nature, are not to be confused with the static effects of intra-firm economies of scale. Learning effects, to the extent that they are industry-wide and result from the actions of a single firm, can represent a technological externality wherever a firm is not able to internalize the value of their experience. Thus, situations may occur in which some form of subsidy is justified.

Zimmerman has summarized the problem of learning effects and their relevance to new energy technologies:

> The policy debate has centered on the wisdom of government subsidy for the construction of large-scale commercial plants. The goal of subsidizing the plants is not to produce new technological information, since the technology is already proved. Rather, the goal is to overcome obstacles to the introduction of the technology by the private sector. These obstacles are claimed to be of an information nature. It is argued that there are significant learning externalities. First, observing other's experience leads to lower construction costs. Since the benefits can be realized by another's investment, there is too little incentive to invest.
>
> Second, private firms know the technology will work, but they do not know how to forecast the costs accurately. The economics of scale-up are unclear and can only be made clear by the construction of large-scale commerical plants. Only the construction of new commercial-sized plants can resolve this.

> Furthermore, the whole industry learns from any firm's investments. (Zimmerman, 1982, 297)

The first set of external effects involve learning by doing while Zimmerman terms the second group "learning about costs" (Zimmerman, 1982, 298). Each case may represent a distortion yet their effects may influence future industry development differently.

The concept of learning by doing is based on the presence, in some industries, of a learning curve. This curve relates marginal unit costs to cumulative industry output and is downward sloping (Spence, 1981). If a firm is able to appropriate the reduced-cost benefits from learning, either through patents or licensing, or if it is the sole firm engaged in a production process, then no externality will occur. There are thus two questions to be asked: does learning by doing actually occur for new energy technologies and, if so, does part of the benefit generated occur as an externality?

Schmalensee (1980) points out that most studies of learning-related cost reductions have shown that these are more relevant for labor-intensive industries rather than capital-intensive industries such as energy. He goes on to cite two studies of learning by doing in development of the nuclear power industry, a highly capital-intensive industry. One of these, by Mooz (1978), showed that indeed capital cost reductions did occur with accumulated experience but that there was no evidence of learning-related externalities since "only the firm constructing a particular reactor

learned from that project how to reduce costs on later plants" (Schmalensee, 1980, 22). The second study, by Joskow and Rozanski (1979) examined the significance of increased reliability of nuclear plants as a function of cumulative industry output. Although they find "technological improvements increasing the ultimate capacity factors of new plants at a rate of about 5 percent per year" (Joskow and Rozanski, 1979, 167), Schmalensee points out that their conclusions apply more to with-in plant rather than industry-wide experience.

An alternative empirical result was produced by Zimmerman (1982), who also tested for learning in the nuclear power industry. He found as well that learning by doing was present and resulted in falling unit capital costs. Using a statistical regression approach, he showed that the first plant reduced the capital cost of the second one by 11.8 percent and the second plant reduced the capital cost of the third by 4 percent. But unlike Mooz, he found that a portion of these benefits were not internalized and did actually occur as an external economy. Based on his analysis, with cumulative completed plants as the measure of experience, the value of the externality was approximately half that of the internalized benefit. Despite this Zimmerman concludes that the cost savings per plant constructed were small and more significantly, they had little effect on the rate of commercialization. Thus, in the final analysis, he is in agreement with Schmalensee that

subsidies would not be justified.

Learning about costs represents a process of reducing uncertainty over technology and its relationship to costs. To the extent that investment decisions are based on inaccurate expected costs, sunk costs can mean large social losses such as in cancellation of the Alsands project, for example. Thus, such information is valuable and problems arise when this information cannot be kept private. Such a situation suggests corrective action. Taking the case of coal gasification, Schmalansee states: "If, for instance, one can learn the costs of high-Btu Coal gasification only by building a commercial-scale plant, and if the knowledge thus gained cannot be patented or kept secret, there may be a case for government support of such a plant's construction." (Schmalansee, 1980, 27).

Merrow et al. (1981), in a study for the Rand Corporation, have shown that for first-of-a-kind energy processing plants, cost overruns can be very significant. In a sample of 44 plants, the average ratio of actual final capital costs to estimates at the R&D stage was 2.04. This ratio fell through successive stages of project development and revised estimates. The major factors influencing cost overruns were: cost uncertainty associated with a project itself due to an early stage of development, uncertainty over the process involved, and external factors such as strikes and regulatory delays. By subtracting out the effects of external factors, Merrow was able to describe

overruns in terms of project and process factors by use of regression analysis.

The resulting equation, which is contained in Appendix 3, made use of a number of explanatory variables with the ratio of estimated to actual cost taken as the dependent variable. One variable incorporated measured the proportion of costs attributable to unproven technology. It can be deduced from the t-statistic calculated for the coefficient, which is by far the largest t-statistic, that learning about costs can significantly influence cost estimation error. Based on the coefficient value for the unproven technology variable, a 10 percent decrease in the proportion of unproven technology costs would result in just under a 5 percent decrease in the average cost estimation error (Merrow et al., 1981). Expressed in elasticity terms and evaluated at variable means, the elasticity of cost growth with respect to the percentage of new technology is -.83 (recall cost growth is defined as the ratio of estimated to actual costs).

Zimmerman (1982) also tested for the presence of learning about costs in his sample of nuclear power projects. He found that this factor was present as well and resulted in a 21 percent reduction in estimation error from the first to the second plant, a reduction of 7 percent from the second to the third, and a 4 percent reduction in estimation error in the fourth plant. According to Zimmerman's calculations, half the value of the information

generated by preceding plants was internalized with the remaining 50 percent representing the externality. Despite this he concludes there was little impact on the rate of commercialization since a large number of plants were commissioned before information from early plants was available. This finding could have great significance with regard to crash development programs for other non-conventional energy technologies in that these programs may prevent the incorporation of information about costs.

Estimation accuracy improves through successive plants as expected capital costs tend to increase with better information and actual capital costs tend to fall with accumulated experience. Thus, the learning by doing and learning about costs phenomena interact making it difficult to predict future industry costs based on expected costs at the precommercial stage. Schmalensee argues that since "such information is difficult to evaluate beforehand" (Schmalensee, 1980, 26), a rational subsidy is virtually impossible. He concludes that although problems exist there is no reason to suspect that such a rational subsidy is uniquely warranted in energy projects.

Aside from questions of cost reductions and estimating accuracy arising from learning is the matter of uncertain environmental effects. A basic paradox exists in that knowledge of these effects from which standards are derived may not be forthcoming until a sufficient number of plants have been operating for some period of time; but investors

may be hesitant to proceed while lacking firm standards on which to base their technology: "To the extent that this dilemna exists, the construction and operation of first-of-a kind facilities may have 'public goods' characteristics that would justify some form of government intervention." (Joskow and Pindyck, 1979, 173).

2.5.2 Security of Supply

Based on the petroleum market disruptions of 1973 and 1979 and continuing tension in the Middle East, considerable uncertainty should be attached to future supplies of foreign oil. There can be little doubt that where supply disruptions occur social costs result. These losses arise from the sharp price increase which is associated with, or precipitated by, a reduction in foreign supplies. An immediate consequence is that consumers of petroleum suffer a loss of consumers' surplus. But losses will extend outside the petroleum market itself. A study by the Canadian Energy Research Institute (CERI) examined the impacts of a permanent oil price increase (Angevine, 1980). The study was based on a 50 percent increase in the import price in 1980, a 24 percent rise in 1981, 12 percent increments in 1982 and 1983 and a 10 percent rise in 1984. The domestic price was also assumed to converge to world levels within 2 years. Angevine concludes that:

> The analysis of the effects of a sharp oil price increase on aggregate production levels, inflation, and employment indicates that they would not be insignificant. Higher energy prices would increase

> unit production costs and selling prices over a wide range of commodities. In fact, the overall rate of inflation is indicated to average about 2.5 percentage points higher during the first five years following the assumed change in domestic oil price policy. The analysis also demonstrates that generally higher prices would weaken aggregate demand, slowing the growth rate of the economy by an average annual percentage factor of 0.6 during the 1980-84 period, and raising the unemployment rate by about 1.3 percentage points during the same time. (Angevine, 1980, 4)

Although social costs from a temporary supply shock would tend to reverse themselves once prices returned to previous levels, historical experience indicates that sudden price increases under these circumstances are generally maintained after supply has normalized.

If a significant cost is associated with any supply disruption, a case can be made for the social cost of imports being greater than the import price (Kline and Weyant, 1982). Powrie and Gainer (1976) evaluate the expected social cost for any possible supply shock as the total social cost associated with the disruption times the probability of that event occurring. An approach such as this results in a probability density function with the area enclosed by the function representing the annual expected cost of a supply shock. This value would be the maximum amount a country would be willing to pay, over and above the current market price, to ensure a certain supply of oil. Adding this value to the import price gives the true social cost of imported oil. Thus, it is argued, a non-appropriable benefit may arise to society to the extent that private firms engaged in liquefaction, or any other form of import

substitution, reduce the volume of imported petroleum (Lee, 1982). This benefit would be equal to the true social cost of each import barrel displaced minus its market price.

On the other hand, more recent instability in OPEC presents the possibility that import prices may be substantially reduced in the future. If capital-intensive import substitution takes place, and prices fall below production costs, a significant social cost could be incurred. Such projects would likely receive sufficient revenue to cover short-run marginal costs but sunk capital costs might never be recovered, imposing both a private and social loss. If this scenario was highly likely, the import 'premium' might well be negative.

Security of supply could be enhanced by a number of methods of which two are worth mentioning. One is based on the premise that if "the true cost of imports exceeds the market price, ... a tariff is necessary to cause import decisions to reflect the full cost of these imports to society." (Schmalensee, 1980, 6). Use of a tariff would be assumed to allow for development of indigenous sources and thus represents a self-sufficiency or import substitution option. An alternative means is the establishment of a strategic stockpile of petroleum. A study by Rowen and Weyant (1982) assessed implications for GNP losses of several sizes of supply disruptions and different strategic stockpile levels. Their results indicated that stockpiles held in either the U.S. or OECD countries-at-large would

produce considerable benefits in the event of major disruptions in supply. Stockpiling would allow for continued importation of oil with the costs of a strategic reserve constituting a form of insurance premium.

An attempt has been made to compare the two options, using Australia as an example (Ulph and Folie, 1981). The alternatives compared are a stockpile equal to 20 percent of annual imports and a tariff allowing self-sufficiency of 50 percent of imports. The latter alternative includes liquefaction and other non-conventional technologies. The social costs of stockpiling are calculated as the purchase price and storage cost of the necessary oil. For self-sufficiency, the social cost is the welfare loss resulting from the tariff. This includes the loss in consumers' surplus from higher prices, plus real production costs (associated with increasing domestic supply) in excess of import costs. Using a 10 percent discount rate it was found that the present value cost of the self-sufficiency option was double that of stockpiling. In addition, the assumed level of self-sufficiency would provide only limited protection against an embargo since some oil would still be imported whereas the stockpile would essentially eliminate the threat, at least for some time. Based on at least one set of assumptions, then, it would seem import substitution may not present the most efficient means of decreasing vulnerability to supply disruptions. If this were more generally true, no subsidy could be justified on security of

supply grounds. This conclusion is enhanced where the possibility of reduced import prices in the future could incur social costs if import substitution is pursued in the interim.

2.5.3 Balance of Payments

The development of an import-substituting non-conventional energy industry might be expected to alleviate several balance of payments problems associated with imported oil. Dawson and Slagorsky suggest two possibilities: a reduction in any balance of payments deficit and a reduction in the "instability in the balance of payments that is occasioned by sharp upward movements in world oil prices" (Dawson and Slagorsky, 1981, 81). They go on to dismiss the latter argument based on the premise that it has not been uncommon for prices of primary products traded internationally to fluctuate widely and therefore such impacts would not be unique to oil imports. It is instead the effect of a reduction in the oil import bill which is most deserving of attention.

The establishment of a non-conventional energy sector, including liquefaction, would have impacts on the balance of payments directly through reduced petroleum imports and through development of an industry which would likely import both capital and materials. In essence, an annual capital outflow (to purchase imports) would be replaced by a large capital inflow initially (during the construction period)

followed by annual debt service and principal payments which, on average, could be a significant proportion of the displaced import charge. Impacts would occur over time in response to initial changes in the trade balance, exchange rate, and foreign exchange reserves.

Powrie (1979) has outlined the effects of an increase in natural gas exports on the balance of payments and his analysis can be readily adapted to the case of import substitution based on the assumption that reduced oil imports would in a sense 'create' foreign exchange reserves which could be used for other purposes. To the extent that liquefaction would parallel gas exports in terms of impacts on the balance of payments, the following initial effects could be expected: increases in the trade balance, exchange rate, foreign reserves, money supply, and national income, and reductions in the government deficit and interest rates. If a non-conventional energy project is partially foreign financed there would also be an increase in foreign indebtedness. Repayment of this indebtedness would serve to offset the effects described above. In the longer run the initial impacts would tend to pale. Powrie summarizes the ultimate impact of increased gas exports as follows:

> First, because it stimulates employment and income, it leads to some increase in demand for imports. Second, because it creates additional earnings of foreign currency, it leads either to an increase in the foreign exchange reserves or to an appreciation of the Canadian dollar in foreign exchange markets, or to some combination of these. Appreciation of the Canadian dollar in turn causes other imports to increase and other exports to decrease. An increase in the foreign exchange reserves will, unless offset

> by other measures at the discretion of the central bank, cause an increase in the domestic money supply and thus lower domestic interest rates, which, in turn, may stimulate the economy and increase the demand for imports, and also reduce net inflows of foreign capital. In short, a given increase in exports sets in motion a series of events which, one way or another, leads to increased imports, reduced other exports, and reduced net capital inflows, in some combination that leaves the overall balance of payments ultimately unimproved. (Powrie, 1979, 19)

It would appear then that as a means of righting some undesirable situation in the balance of payments, substitution of domestically produced oil for imports may not be the answer.

Additional support for this can be found in studies on import substitution in less developed countries during the post-war period. If it could be argued that replacing imported petroleum with non-conventional sources means developing an industry for which no comparative advantage exists, a situation could result similar to that which arose in some post-war LDC's:

> As inefficient industries were brought into existence behind tariff walls, they attracted scarce factors of production away from previously efficient and competitive industries. The exchange rate rose as imports were reduced, lowering prices received by exporters. Efficient export industries were thus forced out of business by the dual taxes of higher factor costs and lower product prices. In a sense, import substitution policies had led to the creation of inefficient, high-cost industries for the manufacture of previously imported goods and the destruction of efficient export industries, without any net gain in employment and with a decrease in the value of output evaluated at world prices. (Grubel, 1977, 118)

A situation such as this would obviously have impacts well beyond the confines of the balance of payments.

A more plausible alternative to import substitution as a means of reducing balance of payments problems arising from a large oil import bill is suggested by Ulph and Folie (1981). In their study of policy options for reducing Australia's increasing dependence on foreign oil they compared import substitution to a policy of 'switching'. This latter approach involves spreading the adjustment to larger oil imports "throughout the traded-goods sector, encouraging the expansion of all export and import-competing sectors" (Ulph and Folie, 1981, 12), rather than absorbing it in the oil sector alone. This would be achieved through a policy of administered devaluation over a lengthy period of time. They find, based on certain assumptions as to import demand and export supply elasticities, that the required devaluation to maintain the relative position of oil among imports would average just under 1 percent per year over 25 years. In fact, they argue that this policy would enhance domestic production of oil, although perhaps only modestly, as the average domestic price of imports rises.

It would seem then that import substitution may not present a preferred means of reducing balance of payments problems associated with a large import bill. This observation would be enhanced where foreign funding is involved since any reduction in capital outflows previously used to purchase imported oil would now be partially offset by debt service and principal payments. Thus, little justification may be found for a non-appropriable benefit

accruing from import substitution.

2.5.4 Employment and Income Benefits

Another argument that has been advanced for the substitution of non-conventional energy sources for imports is the enhancement of income and employment opportunities that would supposedly arise. Such benefits have often been the justification for the erection of trade barriers, not always with the greatest success once a full accounting of all benefits and costs has been made. Before proceeding on this point an explanation as to what constitutes these benefits would be in order.

Employment and income benefits are said to arise where previously unemployed factors of production are put to work either directly or through the multiplier effects emanating from new investment expenditure. Both the construction and operation of large energy process plants result in demands for goods and services from other sectors. As labor income accrues to both direct factors and indirectly linked industries, it is in turn spent resulting in further induced effects.

The sum of direct, indirect, and induced employment effects, where these resources were previously unemployed, would represent a net social gain in output. This is equivalent to saying that unemployed labor has an opportunity cost or shadow price of zero. In many cases, though, direct, indirect and induced income is generated at

the expense of income from production in other sectors, rather than in addition to it. Thus, stimulation of production in some industries is offset by a reduction of activity in others. When this occurs a new project merely draws labor away from existing employment and bids up wages in the process; as a result, some marginal firms are no longer profitable with the higher wage bill and cease production. If this occurred, and no alternative employment for the factors involved existed, a secondary cost would result. This points up the important notion that the incidence of employment and income benefits will rely crucially on the status of resource utilization. Where this is high, and this was the case in Alberta through much of the past decade, it would be difficult to prove that these benefits were not fully negated by secondary costs, resulting in a net effect of zero.

For situations of full or near full employment, general equilibrium analysis would be more appropriate than the partial equilibrium approach embodied in multiplier analysis. In this way, as factors are bid away from existing employment, account can be made for the general rise in factor prices that can be expected. Thus, a new enterprise, such as a large energy project, will be shown to cause an increase in production costs rather than create new real income.

Despite the apparent lack of spinoff income stemming from a project in such a situation, any redistribution of

income will be relevant. Where this occurs, and this falls in line with a stated policy, a non-efficiency or equity benefit may arise.

In the event that resource utilization is not full, as a result of regional and structural factors, employment and income benefits may be more meaningful as efficiency benefits. This may be especially so with large energy projects where direct and spinoff employment is highly visible, especially on a regional scale. Although no data exists on coal liquefaction, analysis done on the now defunct Alsands project would be instructive.

A Canadian Energy Research Institute (CERI) study, sponsored by the nine members of the Alsands consortium, modelled the primary and secondary impacts on income and employment expected to stem from the project (Douglas and MacMillan, 1982). Making use of the Statistics Canada interprovincial input-output table, which adjusts for import leakages, impacts arising in each of five regions were calculated. The direct labor income component accruing nationally from the $7.91 billion construction expenditure (constant 1980 dollars) would have amounted to $4.65 billion. Indirect and induced income from the construction phase would have totalled $5.3 billion. Thus, it could be argued that with the existence of an inexhaustible supply of unemployed labor resources an additional project benefit of just under $10 billion would have accrued. In terms of social accounting, $4.65 billion could be debited from the

construction cost and $5.3 billion could be added to project benefits consisting primarily of oil revenues. These values exclude any consideration of employment or income benefits arising during the operating phase of the project.

The regional distribution of income is also worth noting. Although only 26 percent of direct income during construction is earned in Ontario and Quebec, 52 percent or double this proportion is earned in these provinces as indirect or induced income. Clearly a project of this size does not just benefit the province in which it is located.

One of the assumptions implicit in input-output analysis is that substitution between factors does not occur, as aggregate output changes, or in other words, factor prices are constant. This implies the existence of excess capacity in industry. Had the Alsands project gone ahead, the current situation in Alberta may well have justified such an assumption.

A number of problems arise with entering employment and income effects as efficiency benefits. First, these benefits may be valid in the presence of regional or structural unemployment but not necessarily where a policy-created deficiency in aggregate demand exists. Pearse and Nash state that: "If a government fails to use fiscal or monetary policy to prevent such a deficiency in aggregate demand, it has chosen to sacrifice full employment to the pursuit of other macro-economic objectives" (Pearse and Nash, 1981, 109). Employment of currently unemployed labor in the

project in question would then be argued to mitigate some other stated policy objective, such as price stability, suggesting the existence of an opportunity cost or positive shadow price of this labor.

Secondly, where other investment alternatives exist regionally, and similar employment and income benefits could be expected to arise from these, the occurence of such benefits would be irrelevant to the choice among alternatives, which is the essence of benefit-cost analysis. A related point, where other alternatives are possible, is that the project in question may not be the best means to go about stimulating the regional economy. Thus, if the intention is to enhance regional employment opportunities, and a better route exists, a social cost could actually result from pursuing the project in question instead of preferred alternatives (Dawson and Slagorsky, 1981). This may be especially true of non-conventional energy projects since many of the spinoff effects occur outside the regional accounting stance.

There is an additional aspect of employment and income benefits that may warrant consideration, especially with regard to the Alberta situation. Where dependence on resource revenue is a fact, such as in Alberta, the state of the regional economy can be argued to rise and fall with the prices that are received for its resources. This suggests a relationship between the private profitability of resource projects, on the one hand, and the incidence of employment

and income benefits as determined by the state of excess supply in labor markets, on the other. This can be tested for Alberta by comparing the correlation between the landed import price of oil, which reflects activity in the most relevant resource market, and provincial economic activity, as measured by Gross Domestic Product at Market Prices, to the same measure correlated with Gross National Product instead. The calculated correlation coefficients using current dollars for the 1974-81 period is .960 for Alberta and .936 for Canada (World Oil, 1982; Alberta Bureau of Statistics, 1982). This would suggest that Alberta is indeed more vulnerable to the vagaries of the world oil market. As world prices rise, so does the regional economy, while falling prices would seem to result in widespread unemployment, as witnessed throughout 1982 and 1983.

What is of interest here is that as world prices fall, and the profitability of tar sands and liquefaction ventures diminishes, the employment and income benefits emanating from these projects will acquire greater legitimacy. In effect, where inclusion of these benefits is valid, the social value of a project may be maintained or even increased as non-appropriable benefits serve to offset falling private profitability. Thus, a situation may develop where a project becomes increasingly desirable from a social perspective but progressively less so from a private point of view.

The example of Alsands may serve to illustrate this point. Assuming a 30 year project life, production of 140,000 barrels per day, a 310 day annual operating schedule, and a 7.5 percent discount rate, a $10 drop in the import price for the duration of the project would cause a $5.13 billion drop in the present value of revenue. With direct, indirect, and induced labor income totalling $10 billion in the construction stage alone, if even half amounted to a legitimate efficiency benefit, this loss would be negated. Considering the effects of a more recent $5 per barrel price cut by OPEC in early 1983, sufficent unemployed resources might well be available provincially and nationally to warrant this possibility.

Although much of the analysis in this section has focused on secondary benefits from tar sands projects, the case for liquefaction would be much the same. Certain problems arise when attempts are made to include secondary benefits in the benefit-cost calculus, even in the presence of unemployed resources. It would appear that each project must be examined on its own merits with regard to the current status of economic activity and other viable investment alternatives. It might also be pointed out that potential liquefaction sites tend to be closer to existing population centers than those for tar sand development. This may have implications, from a policy perspective, for the distribution of income stemming from such projects.

2.5.5 Environmental Costs

Although the case for non-appropriable benefits from import substitution has been vigorously argued, the issue of non-appropriable costs has largely been ignored. This issue primarily concerns the occurence of external environmental costs in the production of synthetic fuels. An externality is said to occur when the "consumption or production decisions of one agent affect the consumption or production opportunities open to another directly, rather than through the prices which he faces." (Layard and Walters, 1978, 189). Large industrial processes, such as liquefaction or tar sands developments, are notorious for imposing a large variety of external costs on society, primarily in the form of toxic emissions and effluents, land degradation, thermal and noise pollution, and loss of aesthetic value. Where these costs of production have not been internalized, a social cost ensues which is not reflected in private profitability. Whereas the existence of non-appropriable benefits would suggest that too few of society's resources are devoted to a particular economic activity, non-appropriable costs would result in just the opposite. Thus, the incidence of external environmental costs may, at least to some extent, serve to offset any misallocation of resources resulting from legitimately occurring non-appropriable benefits.

Where environmental externalities occur, economic theory suggests "the use of effluent charges, taxes, and the

like" (Dorfman, 1977, 32). In the real world this may not always be possible or practical with the plethora of external costs that abound among various energy industries. What may be of more importance is the magnitude of environmental costs associated with any single energy technology relative to that of other technologies. To the extent that external costs associated with, say, liquefaction resemble those of coal-fired power generation or tar sands development, it may be difficult to argue that liquefaction should be singled out for corrective measures. Since it is coal liquefaction with which we are primarily interested, we turn now to an assessment of the environmental costs of this technology relative to other uses of coal and non-conventional sources of oil.

External costs in liquefaction can be divided into those arising from coal mine operation and those involving plant operation. Environmental costs of coal strip-mining have been the subject of much attention and discussions of these are plentiful (Cameron, 1980; U.S. Congress, 1982; Blakeman, Draper, and Dwyer, 1982). Problem areas chiefly concern effects on groundwater of acid mine drainage and reclamation of certain soil-types. These would be similar for all coal mines regardless of end use.

Unfortunately, no detailed information is available on the extent of environmental damage arising from a liquefaction plant, owing to the early stage of development. This was discussed earlier as a factor in the regulatory

uncertainty faced by private firms. Despite these limitations, though, some speculation has been made as to the environmental implications which could be expected. A preliminary assessment by the Los Alamos Scientific Laboratory (1980) has outlined the issues that will be involved.

Occupational hazards faced by those employed at a liquefaction complex "closely resemble those in coal mining plus oil refining or petrochemicals manufacture." (Los Alamos Scientific Laboratory, 1980, 10). Chiefly of concern are mechanical hazards, such as those associated with any industrial complex, and fugitive emissions of acutely and chronically toxic substances. This latter category contains a number of compounds found at most petrochemical sites such as carbon monoxide, metal carbonyls, solvents, and acids. It also includes a number of chronically toxic and carcinogenic compounds which result from the chemical nature of liquefied coal and which are more specifically associated with liquefaction.

Liquefaction of coal will also produce emissions of nitrogen oxides, sulfur oxides, and carbon dioxide. The Los Alamos study compared emissions of these substances associated with liquefaction to those associated with the direct combustion of coal. Comparisons were made for both construction and operation phases of production and for fuel end-uses. Their findings, based on emissions per unit of end-use energy, can be summarized as follows:

1. Nitrogen oxides would be higher from liquefaction in the order of 70 percent to 160 percent, depending on the liquefaction process. Emissions would be most significant in the operation and end-use stages.
2. Sulfur oxides ratings depend on the liquefaction process considered. Pyrolysis would result in a significant reduction in emissions, primarily as a result of burning of the char residue. For other processes, emissions would not differ tremendously from direct coal combustion.
3. Carbon dioxide emissions would be increased by approximately 20 percent to 80 percent, depending on the process.

It should be pointed out that by-product carbon dioxide may find a use in enhanced recovery of conventional oil.

As a non-conventional source of oil, liquefaction can most readily be compared to oil from the tar sands. A study by Dynawest Projects Ltd. (1983), aside from determining relative production costs, assessed the relative environmental impact of the two technologies. Using a common project size of 120,000 barrels per day, the land area required (inclusive of mine and tailings pond) would be somewhat greater for liquefaction at 80 km^2, versus 52 km^2 for the tar sand process. Even though land is disturbed by coal mining for a much shorter period of time, the opportunity cost of this land would be on average much higher. This is due to the high agricultural value of much

of the land overlaying coal deposits, whereas land in the tar sands region has virtually no agricultural potential.

Water consumption by both processes is approximately 75,000 m^3 per day or 625 liters per barrel. This represents only a small fraction of the total amount of water actually withdrawn. Since coal deposits are generally located in central or southern Alberta, where water is relatively scarce, water in this region might be expected to have a higher opportunity cost than water in the tar sands area of the north; therefore, committing large quantities of water to liquefaction must be considered in light of the net returns this water could generate elsewhere in the economy. In order to assess the use of water for cooling in a liquefaction plant - the principle use of water in all energy processing plants - against alternative uses, its economic value to liquefaction must first be determined. This is done by estimating the additional costs of moving from use of a cooling technology which is relatively inexpensive but requires large quantities of water to use of a technology which is highly efficient in water use but more costly. Dividing these extra costs by the amount of water freed for other uses gives the economic value of this water to liquefaction.

A recent study by Datametrics (1983) detailed the additional costs associated with reducing industrial water consumption. Although costs were determined for a thermal power plant with a much smaller water demand than a

liquefaction plant, the study states the following:

> Cooling technologies vary little between the different energy processing industries and there appear to be little if any economies of scale relating to cooling costs. (Datametrics, 1983, 45)

Based on the above, results from the study are adapted here to the case of coal liquefaction.

The cooling technology integrated into the Dynawest cost estimate is cooling towers, with a water requirement of about 13 percent of the requirement of a once-through system. By supplementing the cooling towers with air cooling, the coal process could reduce its consumptive water demand by about 80 percent to approximately 15,000 m^3 per day or 125 liters per barrel. Doing so, however, would increase the present value of production costs by about $.61 per m^3 of withdrawal water freed, using a 7.5 percent discount rate and a 25 year project life. Completely eliminating water withdrawals by using a closed system air cooling-refrigeration technology would increase present value costs by about $.89 per m^3 of water freed.

Where net returns to water in alternative uses in a river basin are greater than $.61 per m^3 but less than $.89 per m^3, cooling towers in a liquefaction complex (or in any other energy processing plant) should be supplemented by air cooling. If water in alternative uses has an economic value greater than $.89 per m^3, the closed system approach should be implemented.

Regarding atmospheric emissions, oil sands projects can be expected to generate higher amounts of sulfur than

liquefaction projects due to the higher sulfur content of the bitumen feedstock. These higher sulfur emissions, however, would be somewhat offset by higher particulate emissions from the liquefaction process. As with water use, a comparison of the social costs of the two processes should include the potential for externalities arising from tar sands upgrading as a result of increased sulfur emissions. The acid rain caused by excessive sulfur releases represents a problem for industrialized countries exceeded only, perhaps, by the global impact of carbon dioxide accumulation. One means of reflecting this concern in comparing the two non-conventional technologies is to estimate the costs associated with reducing sulfur emissions from tar sands extraction to the level incurred by liquefaction and include these with the cost estimate for the former.

Perhaps the greatest environmental difference between liquefaction and tar sands extraction is the tailings disposal pond associated with the latter. This presents a problem unique to the tar sands:

> The huge area, generally equal to the mine itself, required to store tailings due to the unsettled sludge problem not only sterilizes future recoverable resources but also is not desirable ecologically. (Prased, 1982, 1)

In comparing the two technologies it is necessary to keep the following in mind; "At the moment there is no known method for the reclamation of the tailings pond that will remain at the conclusion of the oil sand project."

(Dynawest, 1983, 86). This could represent a significant disadvantage to tar sands development over liquefaction despite indicated lower private production costs.

In summary, it appears that liquefaction may pose some serious occupational health costs although the effects of certain carcinogenic compounds require further study. Emissions of nitrogen oxides and carbon dioxide are significantly worsened for liquefaction relative to direct combustion. Sulfur emissions are generally the same or improved relative to direct combustion of coal; compared to oil from tar sands, sulfur emissions from liquefaction are substantially reduced. Particulates will be emitted in quantities similar to direct combustion but somewhat greater than for oil from tar sands. In terms of the opportunity costs associated with land disturbance and water-use, liquefaction will fare worse than the tar sands technology, although these costs may be internalized rather than accrue as externalities. Environmental costs associated with tar sands extraction must also include the uncertain cost imposed by a tailings pond, a problem which is not present with liquefaction.

2.6 Synthesis

Having reviewed the theory and evidence on market failure in non-conventional energy markets, we are now in a position to draw some conclusions. Of primary interest is the question of whether market prices and discount rates

reflect the full social costs involved in oil import substitution. If this were so, a socially optimal rate of commercialization would take place on its own. Where this is not the case, further questions arise as to the appropriateness of adjusting benefit and cost values in the analysis and of applying corrective measures such as subsidies and tariffs.

A first qualification that might be argued concerns the uniqueness of market distortions in energy markets. Schmalensee states:

> Energy markets are imperfect in many ways, but so are markets for textiles and most other goods and services. The many imperfections that society chooses to ignore in the case of textiles should also be ignored in the case of energy, unless the two cases can be qualitatively or quantitatively distinguished. (Schmalensee, 1980, 4)

A second 'test' that a distortion must pass in order to be considered a legitimate extramarket benefit (or cost) of a non-conventional energy investment, is whether an alternative means to this investment exists for correction of the distortion. Where such an alternative exists and is preferred, social benefits perceived to arise from non-conventional energy investments may be negligible or may actually represent social costs.

Based on the above, Schmalensee argues that the only legitimate market distortions associated with non-conventional energy investments are related to regulatory and cost uncertainty as well as certain "institutional obstacles to innovation" (Schmalensee, 1980,

35). By the latter, he refers to any number of barriers to commercialization which once overcome by one firm would result in spillover benefits to subsequent industry entrants. Joskow and Pindyck (1979), in agreement with Schmalansee, suggest that domestic pricing policies represent /the most significant energy market distortion and add 'reflected' risk resulting from uncertain environmental effects as well. They dispute arguments which would seek to include discount rates and learning effects among legitimately occurring distortions. Kline and Weyant (1982) maintain that disincentives for reducing dependence on oil imports primarily relate to excessive regulation of prices and environmental controls. Presumably, these disincentives would be passed on to the commercialization of import-displacing technologies. Wirick (1982) adds taxation and uncertainty over future regulation to the pricing issue and argues these distortions are most responsible for inadequate investment in non-conventional energy.

Where market failure does exist, it can be expected to affect industry development in two ways. First, where social costs and benefits are not adequately reflected in market values, the rate of commercialization may not be optimal. Second, where market price signals are themselves distorted, the optimal choice of inputs may not be made. This latter point may be especially relevant to technologies such as coal liquefaction where a number of input-mixes are possible. Hydrogen requirements for example, can be met via

steam reforming of natural gas or by gasification of coal and by-product residue. Power needs, as well, can be met from a number of different by-product feedstocks or simply purchased.

It is the intent in the following chapters to examine the impacts of two apparent distortions on development of a coal liquefaction industry in Alberta. These two potential market distortions are pricing and discount rates. Serious data limitations restrict the testing for other possible distorting effects, though it is understood that such may occur. Testing for the presence of distorting effects requires both social and private evaluation of liquefaction. Significant discrepancies between the results of each approach would suggest that market failure is present. Before proceeding directly with the analysis the following chapter outlines the technical and cost background to coal liquefaction.

3. Technical Background and Engineering Costs for Coal Liquefaction

3.1 Introduction

The previous chapter detailed the possibilities for market failure in the development of non-conventional energy technologies. It was asserted that distorting factors might particularly affect optimal commercialization of a coal liquefaction industry. Before proceeding with a test of this proposition, it is necessary to outline certain background aspects of liquefaction. First, we examine the historical development and technical status of this synfuel technology. Following this, the costing methodology is explained. Deriving plant costs requires an approach which would include the use of both market input prices and social cost values. For coal, particular attention is paid to the effects of economies of scale on unit costs. Finally, estimated engineering costs for liquefaction are presented for several alternative design or technology 'mixes'.

3.2 Historical Development

Before proceeding with a description of the technology involved in coal liquefaction, a brief review of its historical development would be in order. Much of the following dicussion is based on Lee (1982).

Earliest attempts to convert coal to liquids date back to Friedrick Bergius in Germany in 1913. He was able to

produce a petroleum-like liquid by combining a coal-oil mixture with hydrogen in the presence of a catalyst at elevated temperatures and pressures. Subsequent efforts, again in Germany, resulted in the first liquefaction complex being built by the I.G. Farben Company in 1927. Diminished profitability in the early 1930's led to government support under the Nazi policy to attain self-sufficiency in fuels. During the 1939-45 war, German production of synfuels peaked at 100,000 bbl/day and provided more than half of Germany's total fuel needs.

The post-war United States, noting the success of the German undertaking, and facing "the depressed state of the coal industry, gloomy predictions of a petroleum shortage in the next decade, and the heating up of the Cold War" (Lee, 1982, 9), became very interested in the development of an indigenous synfuels industry based on the Bergius liquefaction technology and oil shale.

The history of synfuels in the United States has unfolded in cycles; each time, an intense push has nearly resulted in government sponsored commercial operations - only to be dethroned by falling oil prices and suddenly dissipating support. The most recent such cycle culminated in the Carter administration's Synthetic Fuels Corporation in 1979, but was preceded by similar events over the period 1943-54.

On a different front, research in Germany led to the discovery in 1925 of the Fischer-Tropsch synthesis, an

indirect liquefaction technique with a middle gasification step. Development of this approach culminated in the commercial-scale Sasol liquefaction plants in South Africa. Although the first plant, Sasol I built in 1950, had major technical difficulties, a subsequent plant appears highly successful and will be followed by a third. To some extent, synfuel development has been aided by the unique international status of South Africa. It would appear that where liquefaction has been successful, non-market forces have been largely responsible. We turn now to the technical aspects of liquefaction.

3.3 Technical Primer

The coal molecule is very complex and has yet to be fully defined (Lee, 1982). It is composed primarily of carbon, hydrogen and oxygen with smaller quantities of nitrogen and sulfur often present. Compared to conventional petroleum, coal has about half as much hydrogen and marginally less carbon. This results in a lower hydrogen-carbon (H/C) ratio which generally typifies a less desirable hydrocarbon fuel. The object of liquefaction then is to increase the H/C ratio which can be done in two ways, either remove carbon or add hydrogen. Existing liquefaction processes use both approaches and are classified accordingly. Direct liquefaction refers to those processes which add hydrogen while pyrolysis involves the removal of carbon. Indirect liquefaction combines the previous two

techniques by both adding hydrogen and taking away carbon.

There are a number of direct liquefaction processes under development and although all involve hydrogen addition or hydrogenation, there are various techniques for adding the hydrogen. Herring (1979) describes some of these techniques:

> Coal can be hydrogenated in a suitable liquid carrier vehicle with or without catalysts. Hydrogen can be added directly to the reactor or the donor solvent can be externally hydrogenated. Alternatively, finely divided coal can be contacted directly with hydrogen or coal extracts can be hydrotreated to produce liquid hydrocarbons. (Herring, 1979, 5)

Table 3-1 shows various direct liquefaction technologies under development in the United States, classified according to method of hydrogenation.

In the case of catalytic hydrogenation, the particular catalyst used can determine the product slate. Use of a zinc chloride catalyst, for example, results in greater gasoline yields (House of Commons, 1981). Poisoning of catalysts can be a problem, though, resulting in expensive regeneration or replacement of the catalysts.

Pyrolysis takes an alternative approach to direct liquefaction by removing carbon in order to increase the H/C ratio. It is a less severe method of coal conversion than hydrogenation. Carbon is removed by concentrating it in a by-product char which can then be used as a solid boiler fuel which is cleaner than the coal from which it is refined. This technology is currently used in the production of coke for the steel industry with the residue being used

Table 3-1 Direct Liquefaction Processes

Non-catalytic	
	- Coalcon
	- Flash Hydrogenation
Indirect-Catalytic	
	- Exxon Donor Solvent
Catalytic	
	- Synthoil
	- Clean Fuels From Coal (CFFC)
	- H-Coal
Dissolution	
	- Solvent Refined Coal (SRCII)
	- Consol Synthetic Fuel (CSF)
	- Supercritical Extraction

Source: Herring (1979)

as a petrochemical feedstock.

Whereas the thermal efficiency (heat content of output/heat content of input) is 65 to 70 percent for direct liquefaction, this value for pyrolysis is 85 to 90 percent when the by-product char is included. Current processes using pyrolysis are the Char-Oil-Energy-Development (COED) process, TOSCOAL process, Occidental Flash Pyrolysis process, and the Lurgi-Ruhrgas process (Herring, 1979). Some interest has been expressed in pursuing pyrolysis as a non-conventional fuel option for Alberta by incorporating it into power production (Herring, 1979; Berkowitz, 1981). This would see useful liquid hydrocarbons extracted from the coal first with the remaining char used to fire boilers for generation of electricity. Such a project has been proposed for the Heatburg area, east of Red Deer, with plans to

export surplus power (Kolisnyk, 1982). Government approval though does not appear to be forthcoming.

The final alternative for conversion of coal to oil is the synthesis or indirect route. Indirect liquefaction involves the distillation of a liquid fuel after first gasifying the coal. From the intermediate gaseous product, composed of carbon monoxide and hydrogen, liquid fuel is produced either by directly synthesizing gasoline or by first transforming the gas to methanol and then to gasoline. The former procedure is known as the Fisher-Tropsch synthesis and is the technology employed in South Africa at present in the Sasol plants. The latter approach has been developed by Mobil and is known as the M-Gas process. The primary drawbacks to indirect liquefaction, despite its proven commercial record, is a low efficiency of under 40% and high capital costs (Thurlow, 1982).

An additional technical consideration is the quality of syncrudes from coal and the resulting upgrading requirements. Liquid fuels derived from coal are not the same as petroleum. They contain more nitrogen and oxygen and less sulfur. This latter fact could allow burning of synthetic fuels with fewer environmental problems due to sulfur dioxides. Table 3-2 shows the composition of several liquid and solid hydrocarbon fuels.

As Table 3-2 indicates, the hydrogen content of bitumen from tar sands is somewhat higher than that of coal. According to a study by Dynawest Ltd. (1983), comparing the

Table 3-2 Chemical Composition of Several Hydrocarbon Fuels

	C	H	O	S	N	OTHER
			(wt.%)			
Sub-bituminous coal	71.0	5.0	16.0	0.5	1.5	6.0
Athabasca bitumen	83.4	10.5	0.3	4.6	0.4	0.8
Colorado Oil shale	84.5	11.2	1.6	0.6	2.0	-
Coal-derived:						
Mid-distillate	88.5	8.9	2.0	0.1	0.6	-
Naptha	83.4	11.2	5.1	0.4	<.1	-
No. 6 Fuel Oil	86.4	11.2	0.3	0.4	2.0	-
Naptha	85.0	15.0	-	-	-	-

Figures may not add due to rounding
Sources: Herring (1979), Kilborn Alberta Ltd. (1981).

technology and economics of syncrude production from tar sands and coal, the hydrogen needs of liquefaction are ten times that of tar sand production. This is due to the fact that bitumen is simply closer in structure to the desired end product.

In order for coal-derived syncrudes to be useful, it is important that they be close substitutes for petroleum-based products. Analysis indicates that syncrudes can be refined by conventional means, despite their high nitrogen content, and can be substituted for petroleum products after minor processing (Fischer and Hildebrand, 1981). Studies show that they would be best used as feedstocks for high octane gasoline and fuel oil and may in fact be cheaper to refine in some cases due to a lower sulfur content.

3.4 Cost Methodology

This section presents the methodology used in determining the costs of undertaking coal liquefaction. The coal conversion project examined can be divided into two components: liquefaction plant and coal mine. Liquefaction plant costs are as yet uncertain since the technology is not commercial. The cost estimating procedure must incorporate this while at the same time allow assessment of both the possible social value of a commercial liquefaction facility and the potential for market failure. The methodology presented for plant costs attempts to incorporate these considerations. Estimation of coal costs is based on selection of a site but costs are not contingent upon this choice since other sites, with similar geological features, would show similar costs. Instead, the site selected is meant to be representative of a lower-cost accessible coal field.

3.4.1 Liquefaction Plant

'Ex post' data on a number of liquefaction plants, which is preferred for economic analysis, does not exist. The absence of any such projects in North America at a commercial scale necessitates the use of engineering cost estimates. It would be reassuring to know that engineering cost estimates for non-conventional energy technologies were generally accurate. Unfortunately, this has not been the case. It has been pointed out that: "The history of cost

estimates for synthetic fuels and other energy process technologies is not one to inspire corporate and government planners with confidence." (Merrow et al., 1981, 1). Allowance for this uncertainty is made in the following chapter.

Data from a study co-sponsored by the provincial and federal energy departments and Algas Resources Ltd. was made available (Kilborn Alberta Ltd., 1981). This study represents the second phase in an on-going project to bring synthetic fuel from coal on-stream in Alberta, should it prove viable. The first phase consisted of the appraisal of a number of different technologies with the emphasis on economic viability (Cangasco Engineering Ltd., 1977). The most promising technology, the Saarberg liquefaction process from West Germany, was then subjected in the second phase study to a more detailed cost estimate including financial feasibility, as determined by rate of return analysis, and bench-scale liquefaction tests of a representative coal.

The Algas study examines two possible designs; one involves purchase of required power, while the other presumes power is generated on-site with a surplus available for sale to the provincial grid. Both alternatives produce hydrogen requirements via the steam-reforming of natural gas. Technical aspects of the process can be described as follows:

> In the proposed process, finely ground coal is slurried with the heavy fraction of the product liquid. The slurry is sent to the liquefaction reactor where it is mixed with hydrogen and catalyst

> to produce light gases, raw hydrocarbon liquids and a solid residue. The raw liquid stream is further processed to yield naphtha and middle distillate fractions and mixed butanes. The naphtha and middle distillate fractions are hydrotreated to reduce sulphur, oxygen and nitrogen content and the mixed butane stream is desulphurized. (Kilborn Alberta Ltd., 1981, 5)

Section 2.6 suggested the existence of additional possibilities for making use of the various co-products involved in liquefaction. In particular, fuel gas generated during the liquefaction process and solid residue remaining afterwards may be used in various ways while still producing identical output of syncrude. In order to incorporate these considerations, costs for two additional sets of design parameters were estimated. These allow for hydrogen production from coal gasification with power generation from fuel gas or coal and solid residue. In the latter case, fuel gas is assumed to displace natural gas use elsewhere in Alberta, freeing it for export.

Costs for the two additional cases were derived from published literature and were adjusted for location, transport, and indirect costs using factors provided in the Algas study. Adjustments in the size of process units, where necessary, were based on an economies of scale factor of .6. This value represents the standard factor used in engineering estimates of such facilities. Justification for its use in economic analysis can be found in Moore (1969). The exception to this was the hydrogen from coal gasification complex which made use of a .8 factor (Dynawest, 1983). Detailed cost estimates are presented in

Appendix 2.

Adjustment for inflation was necessary for both the Algas estimates, which were expressed in 1980 dollars, and the two additional cases. This was accomplished using the Statistics Canada construction cost index for Chemical and Petrochemical Plants (Statistics Canada, 1983a). Final costs are expressed in mid-1982 dollars.

Prices for natural gas and fuel gas are left out of the estimates presented in this chapter due to the divergence between social and private prices for these commodities. It is in part this divergence which leads to the supposition that a private firm might not choose the alternative which is consistent with the social optimum. Socially relevant prices are included as part of the analysis in chapter 4 while the impact of using private prices is examined in the following chapter.

It is assumed for purposes here that there is no divergence between the social value of power, reflected in current marginal replacement costs, and the market price, often set at average cost. Although this may not be a fair assumption for residential and commercial users where distribution costs dominate, for large industrial users this is more realistic since distribution costs are low. Marginal generation costs, which would then be most important, are forecast to remain relatively constant over the medium term (Prottie and McRae, 1980); thus, average costs should closely parallel marginal values. Power purchases in this

study, as a result, are based on current charges to large industrial users, inclusive of transmission costs, while sales have transmission netted-out to reflect returns to generation. It is understood that at this time no mechanism exists for the pricing of electricity sold to the provincial grid but produced outside of it.

3.4.2 Coal

Economic studies of coal liquefaction feasibility have generally included the cost of coal at a constant assumed value (Feick and McConaghy, 1976; Leung and McDonald, 1982; Slagorsky, 1982). This approach is not useful for the analysis at hand since it makes no account for different volumes of coal being available at different unit costs. Allowance for this is important here since the use of various production alternatives for hydrogen, with and without coal-fired power generation, results in unequal coal demands among the four sets of design parameters examined. If economies of scale were not prevalent in coal mining then the assumption of constant unit costs for mines of different sizes would not seem unreasonable. This is not the case, though; in fact, economies of scale have been shown to be significant in coal mining (Zimmerman, 1981). However, before detailing how this condition was incorporated into the cost estimate, we will briefly review the economics of strip mining coal.

Strip mining of coal involves a number of simultaneous operations which require a substantial amount of organization. Overburden is stripped and piled by a large dragline, forming a long 35m to 70m wide pit in the process. Coal is then extracted from the seam by front-end loaders and hauled to processing or storage facilities by huge 100 tonne coal haulers. As the coal is removed from the seam, the pit is refilled with overburden, generally from an adjacent pit. The area is then recontoured and the topsoil is placed back on the surface. Reclamation occurs as part of the on-going mining process.

Strip mining, unlike underground mining, is highly capital-intensive, thus enhancing the notion that coal liquefaction overall is a capital-intensive activity. Costs of strip mining depend primarily on geological factors with the key variable being the strip ratio. This value gives the depth or volume of overburden which must be removed for each meter or tonne of coal below. The strip ratio for a coal field is calculated by dividing total volume of overburden by the volume of coal in a seam. Obviously, as the strip ratio increases, unit extraction costs will as well.

A second influence on cost comes from mine size. Economies of scale dictate that as mine size increases, unit costs will fall. This effect is pervasive enough that the extent of reserves will often limit mine size before economic factors (Zimmerman, 1981). Where it does not, the extent of economies of scale will be defined by the maximum

size of dragline.

A final factor affecting costs is the pattern of extraction over time. Economic theory predicts that the present value of profits is maximized if the lowest cost reserves are extracted first (Veeranna, 1979). Thus, it can be expected that units costs will rise over time as low cost reserves in a coal field are exhausted. In summary, coal unit costs are an increasing function of both the strip ratio and time and a decreasing function of mine size.

Campbell lists 8 coal regions in Alberta which could supply a 50,000 barrel per day liquefaction plant over 30 years. (Campbell, 1982). Locations and strippable reserves are listed in Table 3-3. The Tofield-Dodds area was selected for this study due to the availability of coal cost information contained in an application to the Alberta government by Trans-Alta Utilities for a 2250 MW power station at this site. The application was turned down because of uncertain reclamation potential in the face of a strong agricultural lobby. Obviously, environmental concerns, such as reclamation and water availability, would have to be resolved before this site could be committed to either power generation or liquefaction. For the purpose of this analysis it is not necessary that we assume this occur since the intention is to assess the economics of liquefaction in a general way rather than with regard to any specific site.

Table 3-3 Potential Coal Fields for Liquefaction

Coal Field	Strippable Reserves (MM tonnes)
1. Fox Creek	755
2. South Swan Hills	295
3. Mayerthorpe/Wabamun	155
4. Wetaskiwin	404
5. Red Deer	644
6. Barrhead/Morinville	525
7. Tofield-Dodds/Battle River (part)	787
8. Battle River	314

Source: Campbell (1982)

Coal in the Tofield-Dodds region is sub-bituminous C rank with a heat content of 17.51 MM kJ/t (Montreal Engineering, 1978). Derived demand for coal for the two cases included in the Algas study was based on an energy input of 151.51 x 10^{12} kJ/yr. This results in a nominal coal demand of 8.65 MM t/yr. For the two additional cases, derived demand for coal was determined from process requirements in the Algas study plus the extra volume needed for hydrogen production. Case 3 had a nominal demand of 10.79 MM t/yr. Case 4 also used coal for power generation making its requirements slightly greater at 12.52 MM t/yr.

In order to determine coal costs for different size mines, a marginal cost curve would be necessary.

Unfortunately, the data required to determine such a curve for western Canadian sub-bituminous coal is not readily available; therefore, an alternative approach was taken. A set of econometric cost functions determined for western American coal (Zimmerman, 1981), geologically similar to Canadian conditions, were used to adjust feedstock costs for an Alberta liquefaction facility, where this was necessary. This was done by determining the predicted value of capital and operating costs for each mine size, using these equations. Ratios were then calculated using the predicted value from the data mine as a denominator and the predicted values from the other mine sizes as numerators. Actual data mine costs were then multiplied by these ratios to get total capital and operating costs for each mine used in the analysis. The implication of this approach is that economies of scale would be expected to be identical for both Alberta and western United States locations. This does not seem to be an unreasonable assumption. The calculations described above are contained in Appendix 1.

Costs for the data mine, obtained from Trans-Alta Utilities (Montreal Engineering, 1978), were updated to 1982 values using the Statistics Canada machinery and equipment index for Mines, Quarries, and Oil Wells (Statistics Canada, 1983a). The data mine size was 8.27 MM t/yr, slightly lower than demands for Cases 1 and 2. Since cost data was based on a mine size sufficiently close to Cases 1 and 2, no adjustments for these alternatives were necessary. This,

however, was not the situation for Cases 3 and 4. Information on mine sizes and economies of scale is summarized in Table 3-4.

Based on the premise that low cost reserves are extracted first, replacement capital and operating costs could be expected to increase over time as the strip ratio increases. According to the mine plan for the Trans-Alta power plant, the initial strip ratio would have been 4.13 m^3/t rising to 9.48 m^3/t by the twenty-ninth year. Rather than increase replacement capital and operating costs accordingly, these were averaged over the mine life in order to simplify calculations. This can be justified in that these costs represent only $3 per barrel or about 5 percent of the cost of syncrude produced. As a result of this assumption, it can be anticipated that final present value costs will be slightly overestimated since in reality higher cost extraction would be relegated to the future.

The Algas study makes allowance for the use of beneficiated coal. Beneficiation or cleaning refers to the process by which "most of the free rock particles are removed as well as some proportion of the coal material containing higher-than-desired amounts of mineral matter." (Canada West Foundation, 1980, 53). This requires cost estimation of a coal preparation plant in which beneficiation takes place. This data is available in the form of curves showing costs for various capacities (Cangasco Engineering, 1977). Values for the different

Table 3-4 Data on Coal Cost Adjustments

	Coal Requirements (MM t/yr)	Increase in Mine Size from Data Mine	Increase in Capital Costs from Data Mine	Increase in Operating Costs from Data Mine
Data Mine	8.27	-	-	-
Case 1	8.65	4.6%	0	0
Case 2	8.65	4.6%	0	0
Case 3	10.79	30.5%	16.3%	20.1%
Case 4	12.52	51.4%	26.5%	33.4%

demand cases were derived from these curves and updated using the Statistics Canada Chemical and Petrochemical Plant cost index (Statistics Canada, 1983a). These costs are presented separately from coal mine and liquefaction plant figures.

3.5 Coal Liquefaction Costs: Alternative Design Parameters

Having outlined the cost methodology utilized, we now turn to the estimated costs for the four coal conversion alternatives being examined. The appropriate costs for this analysis are real efficiency costs. These refer to the true resource costs to the economy of a particular activity. This means that monetary transfers such as income taxes or subsidies are not included. This information is provided in chapter 5.

All four alternatives produce an identical output of 60,815 bbl/d of syncrude and 1268 bbl/d of mixed butanes, although outputs of by-products, including power, fuel gas, and sulfur, vary. It should be noted that since values for natural gas and fuel gas are excluded from this section, operating costs for Cases 1,2, and 4 do not reflect the entire yearly cost of producing liquids from coal. Material balances and real efficiency costs for all four alternatives are summarized in Table 3-5. Appendix 2 contains the detailed cost estimates.

3.5.1 Case 1: Hydrogen From Natural Gas and Fuel Gas/Purchased Power (173.5 MW)/Steam from Solid Residue

This approach to liquefaction is characterized by the disposal of most of the solid residue left after the liquefaction reaction, with only a small amount being retained for steam production. Power, rather than being produced on-site, is purchased from the provincial grid. Hydrogen is produced via the steam-reforming of 1826 MM m^3/yr of natural gas with by-product fuel gas used as fuel for the reformer furnace. Table 3-5 presents the material balance and costs for Case 1 in the first column. This input-mix can be characterized as low in capital costs, relative to the other alternatives, since power station costs are zero while initial hydrogen plant and coal mine costs are comparatively low. Operating costs, on the other

Table 3-5 Material Balances And Real Efficiency Costs For Four Sets Of Coal Liquefaction Design Parameters

	CASE 1	CASE 2	CASE 3	CASE 4
MATERIAL BALANCE				
IN: Coal (MM t/yr)	8.65	8.65	10.79	12.52
Natural Gas (MM m^3/yr)	1826	1826	-	-
Power (MW)	173.50	-	-	-
Labor (man-yrs/yr)	880	960	1107	1126
OUT: Syncrude (bbd/d)	60,815	60,815	60,815	60,815
Mixed butanes (bbl/d)	1268	1268	1268	1268
Fuel gas (MM m^3/yr)	-	-	-	1756
Carbon dioxide (MM m^3/yr)	1478	1478	n.a.[1]	n.a.[1]
Power (MW)	-	350	300	-
Sulfur (t/d)	9.8	9.8	148	153
Ammonia (t/d)	118	118	118	118
Soda ash (t/d)	21.8	21.8	21.8	21.8
CAPITAL COST ($ MM 1982)				
Coal mine	362	362	421	458
Coal preparation plant	100	100	114	125
Liquefaction plant	3720	4200	5903	6040
TOTAL[2]	4180	4660	6440	6620
O & M COST ($ MM 1982)				
Coal mine	42.68	42.68	51.25	56.95
Coal preparation plant	6.16	6.16	7.02	7.68
Liquefaction plant:				
Fixed: Contract maintenance	2.00	2.00	2.00	2.00
Insurance/Taxes	62.00	70.00	98.40	100.68
Variable: Labor	26.84	29.28	33.77	34.35
Maintenance	31.00	35.00	49.20	50.34
Power	34.25	(55.88)	(47.90)	-
Sulfur	(0.15)	(0.15)	(2.29)	(2.37)
Ammonia	(14.08)	(14.08)	(14.08)	(14.08)
Soda ash	(0.51)	(0.51)	(0.51)	(0.51)
TOTAL	190.19	114.50	176.86	235.04

[1] not available
[2] Totals are rounded off

hand, are the highest of the four alternatives due to the cost of natural gas, not included here, and the purchase of electricity. Coal requirements amount to 8.65 MM t/yr, which requires the smallest mine of the four alternatives.

3.5.2 Case 2: Hydrogen from Natural Gas and Fuel Gas/Power and Steam from Solid Residue (600 MW)

This represents the favored alternative in the Algas study. Rather than disposing of surplus solid residue, the entire amount is burned in a co-generation power-steam plant which produces 600 MW of power and supplies all process steam requirements. On-site power needs are only 250 MW resulting in a net exportable surplus of 350 MW which is sold to the provincial grid. Hydrogen production is identical to Case 1 with fuel gas, again, utilized as the reformer fuel. Coal requirements, as well, are unchanged at 8.65 MM t/yr.

Column 2 in Table 3-5 lists the material balance and costs for Case 2. It can be observed that capital, maintenance, and fixed operating charges are slightly higher than in Case 1 due to the inclusion of the co-generation plant. To the variable operating cost must be added natural gas costs. Total operating costs are somewhat lower than for Case 1 which serves to offset the higher capital cost.

3.5.3 Case 3: Hydrogen from Solid Residue and Coal/Power and Steam from Fuel Gas (600 MW)

Case 3 represents a substantial departure from the two previous alternatives. Whereas previously hydrogen was produced from the steam reforming of natural gas, it is now produced via the gasification of solid residue and coal. Based on data extraneous to the Algas study, costs were determined for gasification and integrated into the overall capital cost estimate (see Appendix 2). The material balance was maintained wherever possible resulting in necessary adjustments to other process areas; the coal mine, preparation plant, ash handling and disposal facilities, coal handling, and sulfur plant were all increased to accommodate coal requirements of 10.79 MM t/yr.

Sulfur processing would increase significantly, partly from increased coal demand, but most importantly as a result of the redirection of the sulfur-containing solid residue from power generation to hydrogen production. The liquefaction process, by removing a portion of the hydrocarbon content of the coal, causes the sulfur proportion of solid residue to increase by about three times relative to the parent coal. In Case 2, sulfur was oxidized in power generation and emitted directly as sulfur dioxide gas. In Cases 3 and 4, solid residue is gasified instead and much of the sulfur is retained in fuel gas which is then processed for sulfur removal in the sulfur plant.

The gasification of solid residue and coal for hydrogen frees the fuel gas previously used as reformer fuel for other uses. In Case 3 it is assumed that this is used for power generation in a combined-cycle power plant. A combined-cycle plant has three components: a gas turbine, a heat recovery steam generator, and a steam turbine. Fuel gas, with about 65 percent of the heat content of natural gas, is combusted in the gas turbine producing heat and electricity. The heat is channelled to a heat recovery boiler in which steam is generated and used to drive a steam turbine to produce additional electricity. Process steam requirements are met from steam produced in the heat recovery boiler. The fuel gas available is sufficient to generate 600 MW with 300 MW used on-site and the remainder available for sale to the provincial grid. The combined-cycle system is about 42 percent efficient in converting the heat content of fuel to electricity, versus 33 percent in conventional generating systems.

Costs for a combined-cycle plant are just under half of those for a conventional coal-fired steam plant with an equivalent output of electricity. Costs and material balance information are contained in column 3 of Table 3-5. Higher capital costs than those for the previous two alternatives primarily reflect a larger coal mine and the larger outlay for a coal-gasifier hydrogen unit, which is approximately three times the cost of a steam-reformer.

3.5.4 Case 4: Hydrogen from Solid Residue and Coal/Power and Steam from Solid Residue (300 MW)/Fuel Gas Sold

Case 4 can be interpreted as a combination of the previous two alternatives. Hydrogen is provided from gasified coal and residue while power and steam are provided from a co-generation plant. Since additional coal is required to supplement Case 3 requirements, the mine is expanded to 12.52 MM t/yr. Additional adjustments are also made to the ash disposal system, coal preparation and handling, and the sulfur plant. Power plant costs are scaled down from Algas study costs to half the size in order to just meet plant requirements. With power, steam, and hydrogen needs met by coal and solid residue, fuel gas produced is freed to be sold. It must be recalled that this fuel gas has only 65 percent of the heat content of natural gas and would therefore be classified as a medium Btu gas. Thus, the 1756 MM m^3/yr available in Case 4 would amount to 1141 MM m^3/yr of natural gas equivalent.

Costs and material balance information for Case 4 are shown in column 4 of Table 3-5. Capital costs are slightly higher for this alternative, compared to the previous case, since initial outlays for a 300 MW coal-fired power plant exceed those for a 600 MW combined-cycle plant.

4. Economic Analysis of Coal Liquefaction

4.1 Introduction

The aim of this chapter is twofold: to determine the social desirability of coal liquefaction as an alternative to imports and to provide a social evaluation which can be compared to the market or private evaluation outlined in the next chapter. This latter purpose is aimed at checking for the presence of market failure.

Before proceeding with the benefit-cost calculations, a number of considerations are discussed, only some of which can be incorporated into the analysis. Following this, a net present value algorithm is developed and adjusted to account for uncertainty over future world oil prices. Results of the empirical analysis are then provided and discussed.

4.2 Considerations

Assessing the social value of coal liquefaction alternatives requires consideration of a number of factors. For example, significant amounts of uncertainty are associated with future values for several variables and parameters involved in the analysis. This is particularly true of capital costs and oil import prices. Social assessment of projects also involves determining the value of various inputs and outputs in their next-best alternative use. Values calculated in this way may not coincide with accounting prices. This opportunity cost approach to pricing

is particularly relevant in the case of coal liquefaction due to the necessity of committing large reserves of natural gas for hydrogen production which would prevent their use in generating social benefits elsewhere. Production of by-products, such as carbon dioxide and fuel gas, may have a social value or cost and this also should be incorporated into the analysis.

4.2.1 Capital Costs and Uncertainty

As discussed previously under section 2.5.1, capital cost estimates for coal liquefaction, being based on preliminary engineering estimates, are subject to substantial uncertainty. Merrow et al (1981) have confirmed tremendous overruns in actual expenditures for first-of-a-kind energy process plants. Analysis of nuclear power development has also indicated a similar problem in this industry (Zimmerman, 1982). Thus, it may be that estimates for capital outlays developed in chapter 3 will seriously understate final costs. In order to accommodate this possibility, capital costs were incorporated at both their base case values, as outlined in the previous chapter, and at a much higher value based on the Rand cost growth study (Merrow et al., 1981).

In the Rand study, a multiple regression model was used for both descriptive and predictive purposes in assessing cost growth. Based on the results the authors state the following:

> If applied with appropriate care, the statistical models developed here can provide reasonable, early predictions of plant cost and performance for a spectrum of kinds of advanced process plants, including energy process plants. (Merrow et al., 1981, 3)

In order to make use of their model, variable values were determined in consultation with engineering staff at Algas resources. Based on the information they provided and the Rand cost growth equation, it was found that capital costs for the project in question could be expected to increase by 82 percent over estimates provided in the preliminary study. This value would seem to agree with sample means used in the Rand analysis where cost overruns varied from 61 percent to 104 percent for projects at a similar level of development. Data used in this calculation is provided in Appendix 3.

4.2.2 Opportunity Cost of Capital

Also of concern, with regard to capital costs, is the appropriate value to be assigned to the use of funds over the project life. Since liquefaction would be a private domestically funded endeavor, or at least it is assumed to be in this study, funds could be expected to originate in capital markets where competing uses would imply a social opportunity cost equal to the going rate of return on projects of similar dimensions. It was mentioned in chapter 2 that a number of factors might lead to a discrepancy between this social opportunity cost of capital and the social time preference rate. Where this is the case, a

dilemma exists as to the appropriate means of allowing for this divergence. Feldstein suggests the following:

> It is best ... to allow for the social opportunity cost of funds directly by placing a "shadow price" on the funds used in the project and to make all intertemporal comparisons with a social time preference rate or function. (Feldstein, 1972, 247)

The question arises as to how to determine this 'shadow price'.

One alternative to calculating a social opportunity cost of capital or shadow price focuses on how returns from a public or private project are split between consumption and reinvestment. With respect to public expenditure, Mishan outlines this method:

> Owing to the fact that some portion of K (capital) at least would be used for private investment, and earning therefore a return X, the present social worth of K-which is regarded as the social opportunity cost of a public investment requiring a single outlay K- will in general exceed K and may be written as aK, where a>1. (Mishan, 1976, 220)

This 'a' may be called the shadow price of capital. Sugden and Williams (1978) calculate a by first defining i as the return on marginal investment projects - in effect, the private and social opportunity cost of capital discount rate. This return, an amount i generated each year for each dollar invested, can be divided into that portion which is consumed, ci, and a remainder which is reinvested, (1-c)i. The amount reinvested is again subject to the same division since it will also eventually produce a return. Thus, (1-c)i must be multiplied by the shadow price a. Any project producing a return of i will generate annual social benefits

equal to $ci+a(1-c)i$. Assuming these benefits are generated in perpetuity the present value, discounted at the social time preference rate r, would give the shadow price (a) of a dollar of original investment as:

$$a = \frac{ci+a(1-c)i}{r}$$

which reduces to: $$a = \frac{ci}{r-(1-c)i}$$

The shadow value of a capital outlay of K would then be:

$$aK = \frac{ci}{r-(1-c)i} K$$

In this formulation we have both the private discount rate or market rate of interest (i) as well as the social rate of time preference (r). If the two are equal then a reduces to a value of one and there is no shadow price associated with the use of funds.

Unfortunately, use of this approach represents a formidable empirical undertaking. A more practical approach to the problem of shadow pricing has been pointed out by Howe (1971). He argues that where the appropriate opportunity cost of capital and time preference rate diverge, an adjustment factor is required. Where the use of capital funds takes place in perpetuity, this factor is simply the opportunity cost rate divided by the time preference rate. This is equivalent to the simplifying assumption that all returns are consumed or that c=1. This

factor is then used to multiply capital costs before entering them in the net benefit calculation where the time preference rate is used to discount all other benefits and costs. A project with a finite life, the relevant situation for liquefaction, would be adjusted by the following factor:

$$(i/r)\left[1-\left(\frac{1}{1+r}\right)^{m}\right] \Big/ \left[1-\left(\frac{1}{1+i}\right)^{m}\right]$$

where i is the opportunity cost rate, r is the time preference rate, and m is the project life. This approach is analogous to amortizing capital costs at the rate i and then discounting to the present all annual payments with the rate r. Viewing it this way, Howe's approach would appear as follows:

$$\sum^{m}\left[\frac{i}{(1+i)^{m}-1}+i\right]/(1+r)^{t}$$

Here the numerator amounts to a sinking fund charge (Eckstein, 1965). Both formulations produce an identical value.

Whereas simply using a lower discount rate will result in a more favorable project status, Howe states that: "It is not at all clear that a project will present a better benefit-cost ratio by using a low discount factor...if capital costs are adjusted upward." (Howe, 1971, 68). The technique suggested by Howe is used in the present analysis

to allow for an opportunity cost of capital and the discounting of all benefits and costs with a social time preference rate.

4.2.3 Appropriate Social Prices

Economic theory advises that in the social assessment of projects, both inputs and outputs should be priced at their value in the best alternative use. The opportunity cost approach to pricing suggests that where regulated prices exist social values may differ from market prices. In the case of liquefaction, two commodities face regulated prices, syncrude and natural gas (including fuel gas). It remains then to determine what appropriate social values for these commodities would be, given a liquefaction plant commencing production in the early 1990's.

Since we wish to determine the social profitability of producing oil by means of coal liquefaction, the measure of the benefits of this output is taken to be the value of imports displaced. This accords with the notion of alternative cost. Cicchetti has used this approach in assessing the net benefits of Alaskan oil, also expected to displace imports (Cicchetti, 1972). He justifies this by pointing out that if "both alternatives serve the same market and the quality of crudes is similar, then consumers would be indifferent to the two alternative sources of supply." (Cicchetti, 1972, 17).

It remains then to determine what actual import prices will be in 1991, at which time a liquefaction plant is assumed to come on stream. Unfortunately, events in the world oil market over the last decade have served to prevent meaningful predictions of future import prices. Despite this, it is useful to compare the prospects for liquefaction given various initial social values for output. In order to do this, the 1982 import price was calculated, adjusted for quality differences with the coal-based syncrude, and netted-back to Alberta. This gave a plant-gate value for imports displaced. If oil prices remain constant in real terms over the 1982-91 period then this would represent the initial year value of output in 1991, expressed in 1982 dollars. So as to include the possibilities that oil prices may rise or fall in real terms, alternative scenarios were also assessed.

Natural gas prices can be expected to closely follow the movements of oil prices, due to the nature of natural gas as a substitute for oil in the space-heating market. Despite this, the problem arises in determining what an appropriate initial price should be for the natural gas feedstock. For social evaluation it is necessary to price inputs and outputs at their highest and best use. With natural gas, there is reason to believe that in 1990 this will be exports to the U.S., even though this would not be the case at present. The 1982 export price, set at $4.94(U.S.)/MCF, was likely over-valued when it is

considered that only about half of licensed volumes were actually shipped south of the border (Alberta Report, 1983). Recent reductions in the export price in mid-July 1983 have moved somewhat towards enhancing prospects for exports yet the short-term outlook remains bleak given recent additions to U.S. reserves and slumping demand (Alberta Report, 1983). Despite these mitigating factors, long-term prospects for exports appear good and recent projections for U.S. gas supply include Canada as a major source over the next several decades (World Oil, 1983). A recent EUPC forecast states:

> The supply of natural gas in the continental U.S. (even after assuming that higher prices would stimulate increased drilling), will probably decline at a faster rate over the next 25 years than the very slow decline in demand. This imbalance is expected to create a supply shortage by the mid-1980's, creating significent benefits in turn for Alberta. For example, the volume of Alberta gas exports should increase dramatically by 1990. (EUPC, 1983, 3-4)

This will be further enhanced if plans for coal gasification in the U.S. do not materialize.

To accommodate long-run demand for Canadian gas, the price is assumed to equal the U.S. domestic price in 1982, which is somewhat lower than the current Canadian export price. At this level, demand would be presumed to be infinitely elastic and Canadian gas would then represent a perfect substitute for domestic U.S. gas. Thus, initial valuation of natural gas feedstock used for liquefaction in 1991 is taken as this constant 1982 value with alternatives included to parallel possible oil price changes.

4.2.4 Opportunity Cost of Coal

Costs of feedstock coal were outlined in chapter 3. Implicit in those calculations are real efficiency costs for production only. If coal had no other uses, then these would be the appropriate social values for the use of coal in liquefaction. Examination of coal use in Alberta leads to the conclusion that this may or may not be the case.

Provincial coal-use centers around the power generation industry, which is predominantly coal-fired. Total consumption of coal in 1981 for this use was 11.44 MM t (ERCB, 1982a). Derived demand for coal hinges on demand for electricity which in turn relies heavily on provincial economic growth.

Current expections for generation site development would see construction of several coal-fired plants over this decade. This would include 2 375 MW units at each of Keephills, Sheerness, and Genessee (EUPC, 1981). These projects are intended to replace the Camrose-Ryley project which was shelved in the mid-1970's. Capacity of these plants totals 2250 MW and roughly corresponds to demand increases over the 1982-91 period (EUPC, 1983). Subsequent to these planned additions, development of further capacity at all three sites will take place. Indications are that sufficient coal reserves exist at Keephills and Genesee for an additional 4 375 MW units at each site while Sheerness should support at least one additional unit (Fernet, pers. comm.) Forecast supply should also include approximately

1000 MW of peaking capacity from the Slave River project. Total planned supply additions from 1983 onwards sum to 6625 MW. Based on the current EUPC forecast, these additions should satisify peak demands until approximately 2007. Development of Camrose-Ryley or any other sites before this period is highly unlikely due to the economies of scale associated with expansion on existing sites.

Development after currently planned additions is difficult to speculate on. A likely site, in competition with Camrose-Ryley, would be the Ardley area, east of Red Deer, which could support up to 2000 MW (Kolisnyk, 1982). An ERCB document, outlining options to Camrose-Riley, showed slightly lower generation costs for this site over Camrose-Ryley (ERCB, 1976).

Committed coal reserves to generation expansion over the 1983-2007 period can be calculated. Assuming 35 years per plant at a 70 percent capacity factor (ERCB, 1982a), a coal heat rate of 10,550 kJ/kW-hr, and an average heat content of 17,000 MJ/t of coal, the 5625 MW of planned capacity would require about 750 MM t. The ERCB lists strippable reserves at the end of 1981 totalling 6990 MM t (ERCB, 1982b). Thus, coal committments to power sites commissioned between 1983 and 2007 would represent just under 11 percent of the total. If ultimate potential, including underground reserves, is taken as the total, the resulting portion committed is less than one-tenth of one percent. These figures would seem to indicate that power

generation should not restrict the availability of coal for other uses such as liquefaction.

The relevance of this discussion to coal opportunity costs is that although sufficient total reserves exist, the committment of reserves at a site such as Camrose-Ryley to coal conversion means that these are not available for power generation. To the extent that costs for alternative sites will be higher, and the present value cost of the power system is increased, an opportunity cost is associated with the foregone site. The difference in present value costs, where one exists, would be a legitimate rent attributable to the coal in place at the selected liquefaction site and represents a value which liquefaction net benefits must at least equal in order to be considered a best use of that coal. Presumably where no difference in costs was the case, no opportunity cost for power generation would exist. This argument applies to any site where coal reserves are sufficient for either use.

Based on current forecasts it seems unlikely that committment of any potential power site to liquefaction would create opportunity costs before 2005-2010. Any such increase in system costs after this date would need to be discounted back to a liquefaction start-up date. If this were around 1990 and a 7.5 percent discount rate is used, the present value of any increased costs would be reduced by two-thirds to three-quarters.

An alternative opportunity cost of coal may also be relevant. This is the possible exportation of power to the U.S.. A recent exhaustive study outlined export potential for Canada and concluded that Alberta power may be cost-competitive in the California-Nevada market by 1990 (Battle et al., 1983). Although nuclear power costs in that region will likely prohibit development of dedicated capacity, where plants are constructed solely to provide power to the U.S., dedicated energy sales which would displace oil-fired capacity might be feasible. Dedicated energy exports would depend on the cost of delivered Alberta power in the California-Nevada area relative to marginal operation costs of oil-fired plants. This latter value will depend essentially on U.S. fuel oil prices. Although Battle et al. make no mention of competition for oil-fired power markets from western U.S. coal regions, the existence of such competition might significantly inhibit Alberta's opportunities for exports of power.

In terms of coal opportunity costs, electricity exports are similar to power generation for domestic needs. Although total rents accruing to exports might be large if oil prices rise substantially, the rent accruing to generation from any one site will consist of its cost advantage over generation at an alternate, as long as such exists. Thus, this portion of rent would represent an opportunity cost of not using a site for export and would be identical to the opportunity cost of displacing power generated for domestic use. The

only difference would concern timing. Presumably, exports of electricity could be induced once U.S. fuel oil prices rose sufficiently, but issues of rent distribution between U.S. and Canadian participants, reliability, and other legal matters would have to be resolved before exports were possible.

Due to the uncertain nature of future values of coal deposits, their opportunity cost is not explicitly accounted for in the analysis. This approach is enhanced by the existence of potential benefits which may arise from use of carbon dioxide, produced as a by-product of liquefaction, for enhanced oil recovery. This possibility may serve to partially or fully offset any coal opportunity costs resulting from committing low-cost potential power sites to liquefaction. We turn now to a discussion of this issue.

4.2.5 Carbon Dioxide and Enhanced Oil Recovery

Coal liquefaction produces significant volumes of by-product carbon dioxide. This gas, which is detrimental to the environment in large accumulations, has potential for use in enhanced oil recovery. To the degree that carbon dioxide in a useable form is a scarce resource, a rent might be expected to result from its use in enhanced recovery.

An exhaustive study on the subject by Prince (1980), determined that up to 830 MM barrels could be profitably extracted by carbon dioxide miscible flood techniques at $20/bbl in 1978 dollars. However, only 533.8 MM barrels or

64 percent are most profitably extracted using carbon dioxide as opposed to other techniques. In particular, the carbon dioxide miscible approach is in direct competition with hydrocarbon miscible flooding which makes use of methane (Prince, 1980). Thus, the value or rent accruing to scarce carbon dioxide would equal the extra cost of using the hydrocarbon technology for reservoirs in which carbon dioxide was most profitably applied but was not available. Where no other technology could be used, the rent would constitute the entire difference between the cost of enhanced recovery and the oil's import displacement value.

The above argument rests crucially on whether sufficient supplies of carbon dioxide are forthcoming. Prince notes a study done in 1977 on availability of carbon dioxide and concludes supply should just be adequate for anticipated needs (Saturn Engineering, 1977). Since supplies of carbon dioxide rely heavily on petrochemical and other chemical-industrial facilities, developments in the provincial economy since that time may have radically altered the supply outlook. It should be noted that if recovery of carbon dioxide from power plants became viable, supplies would become essentially unconstrained (Prince, 1980).

Demand and supply of carbon dioxide for enhanced recovery depends heavily on the oil price. As this price rises, more recovery projects using carbon dioxide become profitable, increasing demand for the gas. At the same time

greater volumes are supplied as petrochemical activity expands. The situation is further complicated where natural gas prices rise in tandem with oil prices; hydrocarbon miscible flooding becomes more expensive and rents accruing to carbon dioxide will increase.

Potential supply of carbon dioxide from a liquefaction plant, based on Algas estimates for Cases 1 and 2, totals 1478 MM m^3/yr. Carbon dioxide, for these cases, is produced as a by-product of the steam-reforming of natural gas. Volumes produced by Cases 3 and 4, where carbon dioxide is produced as a by-product of gasification, would likely be greater but in a more contaminated form (Fluor Engineers and Constructors Inc., 1979). Exact values are difficult to determine.

Prince (1980) indicates that 69 m^3 of carbon dioxide are required for each barrel recovered by tertiary means. This would suggest supplies from a liquefaction plant (Cases 1 and 2) could provide for recovery of up to 21.4 MM bbl/yr or a total of 535 MM barrels over the 25 year project life. This almost exactly coincides with total potential for all of Alberta from carbon-dioxide enhanced recovery. Thus, it is unlikely that rents would accrue to the entire amount of carbon dioxide produced, given other sources of supply. It is more probable that a much smaller proportion may be required and rents from this could serve to offset coal opportunity costs, where these may occur.

4.3 The Model

In this section an equation for calculating the net benefits of coal liquefaction is formulated. Given the problems associated with forecasting oil prices well into the future, an alternative method of assessing the relative merits of several alternatives is presented. This approach makes use of break-even or annual required increments in the oil price which will render net benefits equal to zero.

4.3.1 An Algorithm For Net Benefits

Measuring or assessing the net benefits of coal liquefaction is primarily an exercise in the application of benefit-cost analysis. Although this technique was originally developed for use in measuring the net welfare gain and thus desirability of public projects, primarily water resources projects for which efficient output markets did not exist, it can be readily applied to the assessment of large private sector projects and indeed has been (Foster Research, 1978).

Conventional benefit-cost formulations generally take the form:

$$PVC = \sum_{t=1}^{m} \frac{OC}{(1+r)^t} + K$$

$$PVB = \sum_{t=1}^{m} \frac{B}{(1+r)^t}$$

Here, the present value of costs (PVC) is equal to the sum

of discounted annual operating costs (OC) over the life of the project (m) plus the original capital outlay (K). The present value of benefits (PVB) is equal to the sum of the discounted benefit stream, where B is annual gross benefits and r is the discount rate applied to both benefits and costs. The net benefits of a project are the difference between the present value of benefits and costs (PVB - PVC).

An inevitable problem in project evaluation is the determination of appropriate price levels. Harberger states:

> It is essential for the proper evaluation of projects to carry out the calculations of costs and benefits in real terms, and the customary way to accomplish this is to express estimated costs and benefits in terms of the price level prevailing at the time the project is being studied...This does not say that costs and benefits should be evaluated by pricing individual products and factors at the levels current at the time of evaluation. Anticipated relative price changes, as distinct from general price level changes should be reflected in cost-benefit analyses. (Harberger, 1972, 118)

In order to accommodate relative price changes, three adjustments have been made to the basic net benefit formulation used here. First, in addition to import-displacing syncrude, the benefit term also includes a butane product, rather than allocating this as a by-product to be debited against operating costs. Second, some alternatives (Cases 2 and 3) produce power for sale to the provincial grid. The value of this output is included as a negative or by-product value with operating costs. Third, natural gas values have been included with the benefit term as negative values where it is purchased (Cases 1 and 2), and as a positive value where fuel gas is sold (Case 4). The

reason for these provisos is that social values for syncrude, butane, and natural gas are assumed to move together at the rate of increase in world oil prices. Based on the possibilities for substitution this seems a reasonable assumption. On the other hand, power values would be assumed to increase in real terms in line with operating costs, since changes in both should in part reflect the supply and demand situation for materials and labor.

Based on the preceeding discussion the following algorithm will represent a statement for the net benefits of liquefaction:

$$b = \sum^{m} (P_i Q_i + P_j Q_j + P_k Q_k)(1+\alpha)^t/(1+r)^t - \sum^{w} a_n \left[(-)\frac{i}{r}\frac{1-(1/1+r)^m}{1-(1/1+i)^m} \right] K/(1+r)^{n-1} - \sum^{m} OC/(1+r)^t$$

where:
- b = net present value of project in 1982 dollars
- P_i = import displacement value of syncrude
- Q_i = annual production of syncrude
- P_j = price of butane product
- Q_j = annual production of butane product
- P_k = export value of natural gas
- Q_k = annual purchases or sales of natural gas equivalent
- K = capital cost in constant dollars
- OC = annual operating cost
- α = annual real increase in world oil prices
- m = project life
- w = construction period
- a_n = proportion of capital cost occurring in year n
- r = social discount rate
- i = gross-of-tax return on capital

Some discussion of this equation would be in order. The

first term represents the present value of net hydrocarbon output (excluding coal) in that syncrude, butane, and natural gas values are incorporated. These would then be expected to rise in real terms at α, the real inflation rate in world oil prices. The second term is capital costs expressed as an adjusted present value. The adjustment factor or shadow price accounts for the discrepancy between the opportunity cost of capital and the social discount rate and was explained in section 4.1.2. The opportunity cost of funds during construction is accounted for by accumulating expenditures over the construction period at the social discount rate. The final term is the present value of operating costs and is based on Table 3-5 in chapter 3. Thus, we have an equation for calculating the net benefits of liquefaction which can be applied to the four alternatives being examined.

4.3.2 Annual Required Oil Price Increment: An Alternative To Net Benefit Analysis

In assessing the economic desirability of a project it is preferable to estimate either the present value of net benefits or a benefit-cost ratio. Unfortunately, with the case of coal liquefaction, it may be undesirable to assess a project with this approach due to uncertainty associated with certain parameters. In particular, the world price of oil, taken as the measure of benefits in this analysis, has been subject to highly erratic and unpredictable changes.

Given that the world price is expressed in U.S. dollars, the exchange rate also plays a role in determining the domestic import cost and uncertainty is also associated with future values of this parameter. These two values can be lumped together to form an uncertain domestic import price. Historic values of this price are shown in Table 4-1.

Some justification for simply incorporating a first year value in a model can be found for prices where uncertain inflation is expected to occur but where deflation is highly improbable. A first year value would then represent a lower bound for benefits. To show the domestic import price as a first year value, however, would be misleading since this value may increase dramatically, as it has in the past, or it may actually decline as has happened more recently. The uncertainty associated with the import price is such that any calculation of net benefits could be rendered obsolete almost immediately.

In order to deal with this problem an approach suggested by Maurice and Smithson (1980) is proposed. In their article they attempt to devise a methodology for dealing with non-conventional technologies where marginal cost functions are not available and scanty engineering cost data must be used. Thus, costs can be assumed to be highly uncertain. The approach used sets the net benefit statement equal to zero and solves the net benefit equation for costs, rather than for net benefits. This value would then represent the highest value that costs could assume and

Table 4-1 Domestic Oil Import Price 1974-81

	World Oil Price ($U.S./Barrel)	Exchange Rate ($ Cdn/$ U.S.)	Domestic Import Price ($ Cdn/barrel)
1974	11.28	.978	11.03
1975	11.02	1.017	11.21
1976	11.77	.986	11.61
1977	12.88	1.0635	13.70
1978	12.93	1.1407	14.75
1979	18.67	1.1714	21.87
1980	30.87	1.1693	36.10
1981	34.51	1.1989	41.37

Sources: World Oil (1982), IMF (1982)

still render the project viable. Brandie et al. (1982) use a similar approach in assessing prospects for tar sands development. Like Maurice and Smithson, they set net benefits equal to zero. However, rather than solve for costs, values for which have already been estimated, they solve for the annual increment in oil prices which will result in zero net benefits. For the case of coal liquefaction, it is this approach which proves most useful.

Since uncertainty over initial hydrocarbon prices was dealt with through several price scenarios while uncertainty over capital costs was incorporated through use of the Rand cost growth model, the remaining uncertain parameter is α, the expected real increase in the domestic import price of oil. If the net present value has been defined as zero and all other parameters are evaluated at their base case or alternative scenario values, the estimating equation can be solved for α in a manner similar to Brandie et al.. This gives an annual real oil price increase which retains the

present value of net benefits equal to zero.

This can be looked at in a different way. For each set of cost parameters there is a particular present value of costs. Each set of oil prices also has a first year value for net hydrocarbon output or benefits attached to it. The value of α which renders the present value of benefits equal to that of costs is the required value.

4.4 Parameter Values

Having outlined the model and approach which will be used to evaluate the four liquefaction alternatives under study, we turn now to determining the values of the model's parameters not yet specified. These include: prices for hydrocarbons (syncrude, butane, and natural gas), discount rates, and construction and operating schedules. Values for capital and operating costs, expressed in constant undiscounted dollars, were presented in Table 3-5 of chapter 3.

4.4.1 Oil Prices

It will be recalled that the social value of synfuels from coal is taken to be the value of imports displaced. This requires calculation of the value of imported petroleum of similar quality, netted-back to the liquefaction plant-gate. An average imported value then will require two adjustments, one for quality differences and one for transportation charges between the point of delivery and the

liquefaction plant.

Adjusting oil prices for quality differentials entails consideration of both density and sulfur content. Higher density fuel, measured by degrees API, is more desirable because a larger proportion of high-valued products can be refined from it. Sulfur, on the other hand, increases refining costs as its proportion increases. In order to make adjustments for these two factors, which differ for average imported petroleum and the coal-based syncrude, a regression equation was employed. Data were obtained on average prices, densities, and sulfur levels of OPEC oil (World Oil, 1982) and density and sulfur values were then regressed against prices to obtain the following equation:

$$\text{Price} = 31.66 + .10321\ \text{API} - .94074\ \text{Sulfur}$$

$$R^2 = .85 \quad \text{S.E.} = .57\ (1.68\%) \quad N = 15$$

Adjustments to the imported value of petroleum were made using the partial derivatives from this equation.

Transportation charges considered here include pipeline costs, pipeline losses, and terminal charges at Montreal, the point for which the landed price is calculated. Values for these parameters as well as the average import price in mid-1982 were obtained from the Petroleum Compensation Board. The net-back calculation for syncrude is presented in Table 4-2.

The price for the mixed butane product was taken as $28.66/bbl and was obtained from the Alberta Petroleum

Table 4-2 Net-Back Social Value of Syncrude

Product	Values ($/bbl)	Comments
Imported Petroleum	41.08	32°API, 1.75% sulfur, landed at Montreal, July 1982. (Kosegi, pers. comm.)
	+ 1.39	Quality adjustment to 29.5°API, 0% sulfur based on OPEC price differentials (see text)
	- 1.21	Interprovincial and Lakehead pipeline, Edmonton to Montreal; pipeline losses; Montreal terminal charge (Kosegi, pers. comm.)
Syncrude	41.26	Net-back Alberta price for 29.5°API, 0% sulfur.

Marketing Commission (Macdonald, pers. comm.).

Outputs of syncrude and butane for all four liquefaction alternatives amount to 18.85 MM bbl/yr and .393 MM bbl/yr, respectively (Kilborn Alberta Ltd., 1981). The total first year value of syncrude and butane in 1982 dollars is $788.97 MM.

4.4.2 Natural Gas Price

The export price for natural gas, taken as the next-best use value for this commodity, presents some problems for calculation. Section 4.1.3 outlined the selection of the U.S. domestic price as the appropriate value. However, many different price levels for natural gas exist in the U.S., due to the fact that it is regulated by

the NGPA or Natural Gas Policy Act (World Oil, 1983). Crouse (1983) lists three different average prices for 1982: an average domestic price of $2.40/MCF (U.S.), an average section 102 (NGPA) price of $3.14/MCF, and an average section 103 (NGPA) price of $2.64/MCF. The value of Canadian gas should theoretically be slightly below the highest price domestic U.S. gas, in order to induce substitution. For purposes here we take the section 102 price of $3.14/MCF as an approximation for the substitute value of Canadian gas in the U.S..

For conversion of U.S. dollars to Canadian, an exchange rate of .80 ($U.S./$Cdn) is used. This suggests a Canadian export value of $3.93/MCF or $138.74/M m^3. Net output of natural gas for Cases 1 and 2 is -1826 MM m^3/yr. For Case 3 there is no input or output of natural gas or fuel gas. Case 4 includes sales of 1756 MM m^3/yr of fuel gas. Since this medium Btu gas is evaluated at 65 percent of the heat content of methane, output of natural gas equivalent for Case 4 is 1142 MM m^3/yr. Total first year values for natural gas are: -$253.34 MM for Cases 1 and 2, zero for Case 3, and $158.44 MM for Case 4.

Total first year values for net hydrocarbon output (excluding coal) are presented in Table 4-3 for the four sets of design parameters being considered. These values reflect 1982 prices for these commodities which would be expected to increase at α, the annual increment in world oil prices, over the project life.

Table 4-3 First Year Social Values for Net Hydrocarbon Output ($ MM 1982)

	Case 1	Case 2	Case 3	Case 4
Syncrude	777.75	777.75	777.75	777.75
Butane	11.22	11.22	11.22	11.22
Natural Gas	-253.34	-253.34	-	158.44
Total	535.63	535.63	788.97	947.41

4.4.3 Discount Rates and Schedules

Choice of a real discount rate requires two values, an opportunity cost of capital and a social time preference rate. This requirement arises as a result of the inclusion of an adjustment factor applied to capital costs which reflects the assumed divergence between these two rates.

The opportunity cost of capital reflects the gross-of-tax real rate of return on domestic capital. Several studies have estimated this value with most authors arriving at a number in the area of 10 percent (Treasury Board, 1976). A more recent study from the Economic Council of Canada estimated the average real before-tax return to capital over the period 1947-1976 (Tarasofsky et al., 1981). This value for the manufacturing sector was 10.2 percent and is used in this analysis to reflect the opportunity cost of funds invested in a coal liquefaction facility.

The problems associated with selecting an appropriate social time preference rate were alluded to earlier in this

thesis. To bypass the great uncertainty associated with any single value, several values are selected and used throughout the analysis. The maximum value is taken as 10.2 percent. This implies an opportunity cost of capital approach to discounting in that the opportunity cost rate and time preference rate are equal and the shadow price of capital is one. A lower bound rate is assumed to be 4 percent. Wirick (1982) uses this rate in comparing market returns to social returns from tar sand development. He argues that the appropriate rate should be the "average real interest cost of foreign debt financing" (Wirick, 1982, 552) and bases his choice of 4 percent on empirical work by Burgess (1981). It remains then to choose a median rate. Burgess, in the same 1981 article, arrives at an overall social discount rate of 7.0-7.5 percent. For this thesis, a median value of 7.5 percent is chosen.

An additional consideration for project analysis, especially with regard to discounting, is scheduling. Capital costs for large projects take place over several years and this has implications for the cost of funds. The operation phase also includes scheduling parameters such as project life and operating days per year.

The construction schedule is assumed to follow the expenditure pattern in the Algas Study. Combining this with a start-up date of 1991 leads to the following yearly distribution of expenditures:

1985	5%	1988	30%
1986	10%	1989	30%
1987	15%	1990	10%

The project life assumed in the Algas Study is 25 years along with continuous operation over 310 days per year. In addition, the Algas Study suggests a phased-in production schedule with first year output at 50 percent of potential and rising from 70 percent to 100 percent in 10 percent intervals over the following 4 years. Incorporating this into the estimation procedure proved difficult so it was dropped. Instead a production level of 100 percent was assumed from the onset. This would lead to a slightly optimistic bias in results where Algas values reflect actual circumstances.

4.5 Results

In this section, annual required oil price increments for four sets of design parameters are presented. These are based on several scenarios for real oil price levels in 1991 and alternative values for final capital costs. A discussion of the findings follows a brief description of the scenarios employed and a presentation of the results.

4.5.1 Annual Required Oil Price Increments for Alternative 1982-91 Oil Price Scenarios

Section 4.1 outlined the reasons for including several possibilities for both ultimate capital costs and real 1991 oil prices. It is the purpose here to describe in detail the

scenarios which arise from these assumptions.

Three oil price scenarios for each of two sets of capital costs are utilized. Capital costs are assessed at both the base level suggested in the Algas Study and at a level 82 percent higher, based on the predicted value for final costs from the Rand cost growth model. Real 1991 oil prices are assumed to follow from one of three patterns. First, a supply shock is assumed sometime during the 1982-1991 period and leads to a real level 15 percent higher in 1991 than in 1982. This roughly corresponds to a real annual increase of 2 percent per year over the 9 year interim period. Second, prices are assumed to remain approximately constant in real terms over the next decade. This concurs with at least one current forecast (EUPC, 1983). Third, a scenario of falling real oil prices is examined. This possibility exists due to recent changes in the world oil market and has been suggested as a distinct possibility (IMF, 1983). Therefore, a scenario of real oil prices 15 percent lower in 1991 over 1982 levels is examined, corresponding to an annual decline of about 2 percent over this period. It should be noted that these scenarios assume the continued existence of the OPEC cartel.

An additional consideration stemming from varying real 1991 oil prices is effects on liquefaction costs. The link between international oil prices and economic activity in Alberta has been discussed at several points thusfar: high oil prices tend to be correlated with high levels of

activity. It has been shown elsewhere that during the period of rapidly escalating oil prices which characterized the 1970's, capital and operating costs for large non-conventional energy projects increased significantly in real terms (Brandie et al., 1982). Should such a scenario be repeated in the 1980's, it might be expected that costs would again increase in real terms. Thus, in line with a 15 percent increase in oil prices, a similar increase is postulated for real construction costs. This again translates to a 2 percent per year real annual rate. A scenario of constant real oil prices is likewise presumed to be reflected in constant 1982 construction costs. The falling real price alternative may also be expected to result in falling real construction costs. This does not seem unrealistic given the lag in recent construction activity in Alberta following a 15 percent drop by OPEC in early 1983. Real 1982 capital costs under this 1991 price regime are assumed to drop by 15 percent by that year, reflecting an approximate 2 percent annual decrease.

Operating costs are assumed to move in line with both construction costs and oil prices. A 15 percent increase in oil prices by 1991 is taken to result in operating cost escalation of 2 percent per year in real terms over the 1982-1991 period. Constant real oil prices are assumed to be associated with constant operating costs while falling real oil prices over the 1982-1991 are presumed to lead to an annual decrease of 2 percent in project operating costs. It

is accepted that the potential cost adjustments suggested here are somewhat hypothetical and as such are intended only to reflect directions of movement.

Based on the above assumptions and the model presented in section 4.2.1, annual required oil price increments for four sets of design parameters were calculated. These values for discount rates of 4 percent, 7.5 percent, and 10.2 percent are presented in Tables 4-4 and 4-5.

4.5.2 Discussion

The results indicated in Tables 4-4 and 4-5 can be analysed from two perspectives. First of all, these figures give an idea as to the overall potential for coal liquefaction in Alberta. Secondly, the assessment of four different sets of design parameters allows a determination of the most profitable approach from the point of view of social valuation.

It should be recalled that annual required increments in oil prices are those values for which higher actual inflation in import prices will create positive net benefits, while lower values will result in net losses. Values in Tables 4-4 and 4-5 can be compared to current expectations and past experience with oil price inflation, in order to determine whether liquefaction could provide a viable means of import substitution. Based on Table 4-1 and consumer price index data (Alberta Bureau of Statistics, 1982), the real average annual rate of change in imported

Table 4-4 Annual Required Oil Price Increments for Four Liquefaction Cases Under Alternative Oil Price and Discount Rate Scenarios - Base Capital

Discount Rate	Case 1	Case 2	Case 3	Case 4
		(% change/yr)		
Base Capital / Constant Real Oil Price 1982-91				
4.0%	2.34	2.12	1.75	.84
7.5%	3.28	3.10	2.66	1.58
10.2%	4.15	4.01	3.49	2.30
Base Capital / High Real 1991 Oil Price				
4.0%	2.21	1.97	1.60	.69
7.5%	3.11	2.91	2.47	1.39
10.2%	3.96	3.80	3.30	2.08
Base Capital / Low Real 1991 Oil Price				
4.0%	2.61	2.43	2.06	1.15
7.5%	3.59	3.46	3.02	1.95
10.2%	4.52	4.43	3.94	2.73

Table 4-5 Annual Required Oil Price Increments for Four Liquefaction Cases Under Alternative Oil Price and Discount Rate Scenarios - Rand Capital

Discount Rate	Case 1	Case 2	Case 3	Case 4
		(% change/yr)		
Rand Cost Growth / Constant Real Oil Price 1982-91				
4.0%	5.91	6.09	5.73	4.84
7.5%	7.35	7.59	7.19	6.18
10.2%	8.63	8.92	8.48	7.39
Rand Cost Growth / High Real 1991 Oil Price				
4.0%	5.78	5.96	5.60	4.70
7.5%	7.69	7.43	7.02	6.02
10.2%	8.46	8.74	8.30	7.20
Rand Cost Growth / Low Real 1991 Oil Price				
4.0%	6.16	6.37	6.01	5.12
7.5%	7.64	7.90	7.49	6.50
10.2%	8.95	9.26	8.83	7.75

oil prices over the 1974 to 1981 period was about 10 percent. This does not include the dramatic increase from 1973 to 1974. Current forecasts for the 1982 to 2000 period project a relatively constant real price to 1990, rising slightly after that (EUPC, 1983; IMF, 1983).

For base capital costs, results indicate the possibility of a viable liquefaction industry is far from remote, no matter which price scenario is examined. For this set of capital costs the range of required increments is from .69 percent per year for Case 4 at a 4 percent discount rate to 4.52 percent per year for Case 3 at 10.2 percent. Required increments are uniformly highest for the 10.2 percent rate and lowest at 4 percent. This agrees with notions that a capital-intensive project will show less favorably at higher rates of discount. Not surprisingly, the high price scenario shows the best prospects and this is followed by the constant and lower price cases. The use of real construction cost inflation for the high price scenario and deflation for the low price situation obviously does not serve to completely offset rising or falling interim oil prices.

The Rand cost growth scenario for capital costs proves less optimistic, as should be expected. Values for this case, shown in Table 4-5, are generally 3 to 4 percent per year higher than under base capital assumptions. Despite this, rankings for price scenarios and discount rates are identical to the base case.

An inspection of the results for the four different liquefaction alternatives shows that Case 4 consistently requires the lowest necessary annual oil price increment to provide zero net benefits, among all price and cost scenarios. Intra-alternative results can be viewed most meaningfully in terms of the 'switching' process which is inherent in the allocation of solid residue and fuel gas to different uses. This can be seen more clearly in Table 4-6.

The movement from Case 1 to Case 2 represents use of solid residue for power rather than disposal. Based on the estimated values under base capital costs (Table 4-4), this allocation is socially profitable since power from liquefaction is produced cheaper than the cost of purchases from the provincial grid. For Rand costs (Table 4-5), this ranking is reversed since higher initial capital costs lead to more expensive power generation at a liquefaction site. This, of course, assumes that cost overruns affect the power component of costs and the rest of capital costs equally. If this was not realistic, results might be reversed. To test this, an additional calculation for Case 2 was done excluding power capital from the Rand cost growth overrun. Using the constant oil price scenario and a 7.5 percent discount rate, the estimated increment for Case 2 was 7.26 percent per year compared to 7.35 percent per year for Case 1, confirming that a reversal would occur.

Cases 2 and 3 provide an interesting contrast in that equal amounts of power and hydrogen are produced but

TABLE 4-6 Allocation of Solid Residue and Fuel Gas Among Liquefaction Cases

	Solid Residue	Fuel Gas
Case 1	waste	hydrogen
Case 2	power	hydrogen
Case 3	hydrogen	power
Case 4	hydrogen	sold

feedstocks for each are switched. What is tested then is the potential net saving involved in this switch. This can be expressed as $(PC_2 - PC_3) - (H_2 - H_3)$, where: PC_2 is present value power costs for Case 2 using solid residue, PC_3 is present value power costs for Case 3 using fuel gas, H_2 is present value hydrogen costs for Case 2 using natural gas and fuel gas, and H_3 is present value hydrogen costs for Case 3 using coal and solid residue. For values of this expression greater than zero Case 2 will be favored, while values less than zero favor Case 3. Based on both Tables 4-4 and 4-5 it appears the net savings involved in switching feedstocks favor Case 3 throughout. This would become less pronounced if the export value of natural gas was lower.

Calculation of a threshold export price of natural gas which would equate required increments for Cases 2 and 3 (base capital, constant oil price, 7.5 percent discount rate) results in a value of $3.55/MCF (Cdn) or $2.84/MCF (U.S.). Export prices greater than this favor Case 3 over

Case 4 while for lower prices, the opposite is true. Since $3.55/MCF is relatively near $3.93/MCF, the value assumed in the analysis, results must be accepted as sensitive to the price of this parameter.

Case 4, as previously mentioned, provides the most favorable set of design parameters in terms of social profit potential. Implicit in this case is the assumption that fuel gas sales are possible and can free currently used natural gas for export sale. Results for this case can be meaningfully contrasted to Case 3 where fuel gas is used for power generation.

Differences between required oil price increments for Cases 3 and 4 can be expressed as $(FG_4 - PC_4) - (PB_3 - PC_3)$, where: FG_4 is the present value of fuel gas sales in Case 4, PC_4 is the present value costs of coal-fired power in Case 4, PB_3 is the present value of power sales in Case 3, and PC_3 is the present value costs of power in Case 3 using fuel gas. Where this sum is positive Case 4 will dominate Case 3 while a negative value implies the opposite. Again the sensitive parameter here is the natural gas export price. Calculation of a threshold value which equates the above-mentioned sum to zero yields a figure of $1.67/MCF (Cdn) or $1.25/MCF (U.S.). Prices above this value cause Case 4 to dominate Case 3. The relatively low value indicates a lower sensitivity to changes in ranking than is indicated between Cases 2 and 3.

In summary, liquefaction could provide a reasonable option to oil imports in 1991 based on the assumption that costs outlined in the Algas study source are accurate and that price and cost inflation scenarios are realistic. If the Rand cost adjustment results in more meaningful costs, liquefaction is unlikely to present a viable alternate source of oil. Hydrogen from gasified coal, which allows fuel gas to displace exportable natural gas, is the favored liquefaction design over all cost and price scenarios. Should this option not be workable, hydrogen from coal is still the desired route over natural gas reforming where oil and natural gas are priced at their social opportunity costs. Some results appear sensitive to the natural gas export price which advises some caution in drawing conclusions. An alternative evaluation with use of financial analysis parameters such as taxes and market prices is examined for its implications in the next chapter.

5. Financial Analysis of Coal Liquefaction

5.1 Introduction

Potential for coal liquefaction using a social returns perspective was the focus of the preceding chapter. However, liquefaction, should it be undertaken, would likely be a private pursuit and this raises additional questions aside from social returns. Chapter 2 discussed the possible implications of market failure on oil import substitution. Based on that analysis, it was concluded that distortions in pricing as well as a divergence between social and private discount rates, whether from taxes or different perceptions of risk, could lead to an inconsistency between the social and private desirability of liquefaction alternatives.

In order to test for possible market failure, a financial analysis was performed. Relevant accounting parameters were incorporated to reflect, where possible, the private circumstances of undertaking coal liquefaction. Unfortunately, due to the lack of existing liquefaction projects, the approach taken must be accepted as somewhat hypothetical. This speculative aspect is enhanced when it is considered that current tar sands projects have been subject to unique financial parameters negotiated on a project-by-project basis. Nonetheless, results from this exercise should help demonstrate the significance of market distorting factors on the private sector's desires to invest in large non-conventional energy projects such as coal

liquefaction. Before presenting the results, we will briefly address the unique elements that must be included as part of the financial analysis, as well as detailing the algorithm employed.

5.2 Formulation

A private accounting stance must reflect the market prices faced by a private firm. For liquefaction this means that market values for syncrude, butane, and natural gas must be used in addition to the real efficiency cost data presented in Table 3-5 of chapter 3. Whereas chapter 4 used the import displacement value of syncrude as the measure of benefit, the relevant price here is contained in the 1980 energy pricing agreement between the Federal and Alberta governments. This New Oil Reference Price or NORP is assumed to apply to products of coal conversion based on the following:

> Effective January 1, 1982, a New Oil Reference Price (NORP) will apply to new oil, that is to say, conventional new oil in Alberta, synthetic oil (including existing Suncor and Syncrude production) and oil from Canada Lands. (Memorandum of Agreement..., 1981)

The 1981 pricing agreement is also responsible for regulating the domestic natural gas price.

Taxes represent a legitimate cost to private firms and as such they are included in the financial analysis. Specific considerations are: corporate income taxes, royalties, and a capital cost allowance. For purposes here, liquefaction is assumed to be a manufacturing activity

facing standard tax and allowable depreciation rates for such endeavors. Brandie et al. (1982) take a similar approach in their analysis of a hypothetical tar sands project.

Royalty payments represent some difficulty due to the singular nature of coal liquefaction. Tar sands projects constructed thusfar face either a gross revenue or profit-sharing royalty based on the status of bitumen as a form of petroleum feedstock which is extracted and upgraded. Liquefaction, on the other hand, entails conversion of coal, which faces its own royalty schedule, into a petroleum-like substance which as a substitute for oil might also require royalty payments. For purposes here, it is assumed that a royalty is paid only on coal. This is justified in two ways. First, payment of double royalties would not seem in keeping with the theory of extracting rents from 'in situ' mineral resources nor does it seem fair. Second, the government coal policy states that a royalty is payable "as a percent of the quantity of coal used or marketed or in dollars as a percent of the deemed value of the coal used or the revenue received from the coal marketed." (Alberta Energy and Natural Resources, 1976, 10). This suggests that it is the raw coal which is subject to the royalty. It is understood that there is little precedence for resolving this issue and that other approaches could be justified.

Taxes were recognized in chapter 2 as being one reason for a divergence between private and social discount rates.

Other possibilities such as differing perceptions of risk were also mentioned to explain high desired after-tax returns on investments in non-conventional energy. Allowance for higher private rates of return based on 100 percent domestic equity financing is included here to test their impacts on the private profitability of liquefaction. A value approximating the desired rate for the Alsands project is used as a base value with several variations for sensitivity purposes.

Rents from carbon dioxide are assumed to accrue to operators of tertiary recovery projects following the approach taken by Prince (1980). Where this gas is in short supply, producers of carbon dioxide may be able to extract some share of this and supplement their revenue stream.

Opportunity costs of coal are also not explicitly accounted for privately although cases may exist where the owner of rights to a coal deposit may have the option of conversion or power generation. In this circumstance the social opportunity cost would be 'internalized' and this would be reflected in desired returns from a coal conversion project.

In order to incorporate the considerations discussed above, an algorithm developed by Kalymon (1979) for assessing net revenue of large energy projects was utilized. This equation, modified for application to liquefaction, is represented as follows:

$$b = \sum^{m}(P_iQ_i+P_jQ_j+P_kQ_k)(1+\alpha)^t(1-\lambda)/(1+i)^t - [1-(\lambda d/i+d)] \sum^{w} a_nK/(1+i)^{n+1} - \sum^{m}(OC+R)(1-\lambda)/(1+i)^t$$

where:
- b = net present value of project in 1982 dollars
- P_i = domestic price of syncrude
- Q_i = annual production of syncrude
- P_j = price of Butane product
- Q_j = annual production of Butane product
- P_k = domestic price of natural gas
- Q_k = annual purchases or sales of natural gas equivalent
- K = capital cost in constant dollars
- OC = annual operating cost
- R = annual coal royalty
- α = annual real increase in domestic oil prices
- λ = corporate income tax rate
- d = capital cost allowance rate
- m = project life
- w = construction period
- a_n = proportion of capital cost occurring in year n
- i = real after-tax rate of return

This equation differs from the formulation used in chapter 4 with the inclusion of taxes, capital cost allowance, a royalty on coal, and domestic prices applied to syncrude and natural gas. It also excludes the adjustment factor applied to capital costs which reflected a divergence between the social time preference and opportunity cost of capital rates. Interest during construction is accumulated over the construction period similarly to chapter 4 but at the required real after-tax rate of return rather than at the social discount rate. The term $\lambda d/i+d$, multiplying the present value of capital costs, represents a "tax shield" (Kalymon, 1979, 3) in that speeded up depreciation defers income taxes and results in a higher present value of net

revenue.

As in chapter 4, the approach taken here is to calculate a required annual increment in oil prices which results in a zero present value of net revenues. In this chapter, however, it is not a required rate of change in the world oil price we are calculating since we are pricing at domestic levels. What is measured here instead is the annual required increase in these latter values. Since we wish to estimate the required annual increase in benefits in both cases, whether or not domestic prices change in tandem with world oil prices is irrelevant. It does not seem implausible though that domestic prices, although not pegged at world levels, will at least move in approximately the same way.

5.3 Parameter Values

Estimation of parameter values to be used in the financial analysis involves determining prices for syncrude, butane, and natural gas, and rates of return, taxes (including royalties), and capital cost allowance. Construction and operating schedules implemented are identical to those outlined in section 4.3.3.

The NORP applied to syncrude is based on a January to March 1982 average import ceiling price adjusted for quality differences, as per the 1981 pricing agreement, and netted-back to Alberta. This follows a similar procedure employed in the previous chapter. The calculated value is shown in Table 5-1. The market price for syncrude of

Table 5-1 Net-Back Market Price of Syncrude

Product	Values ($/bbl)	Comments
NORP	$41.30	38° API, 5% sulfur at Montreal, January-March, 1982 average. (Kosegi, pers. comm.)
	- 1.79	Quality adjustment to 29.5° API, 0% sulfur based on 1981 Pricing Agreement.
	- 1.21	Transportation charges Edmonton to Montreal. (see Table 4-2).
Syncrude	$38.30	Net-back Alberta price for 29.5° API, 0% sulfur.

$38.30/bbl is approximately $3/bbl less than the import displacement value of $41.26/bbl. This is in part explained by the fact that adjustment factors based on OPEC price differentials amounted to 10.3¢/°API and 94¢/1% sulfur while factors included in the 1981 Pricing Agreement were 22¢/°API and $1.65/1% sulfur.

The price for butane is taken as $28.55/bbl, equal to the value used in the social evaluation.

For natural gas, the mid-1982 domestic price of $2.04/MCF or $72.01/M m^3 is used (EMR, 1983). This compares to an export value employed in the previous chapter of $3.93/MCF or $138.74/M m^3, which is roughly double the domestic price.

Outputs and inputs of syncrude, butane, and natural gas for the financial analysis are identical to volumes

indicated in Table 3-5 and used in chapter 4. Based on the above prices and the stated annual volumes, first year total values are shown in Table 5-2. It should be recalled that these values are expected to rise annually in real terms at rate α.

Corporate income tax rates included are those for similar industrial enterprises. A net federal rate of 36 percent and a provincial rate of 11 percent are used (Statistics Canada, 1983b). Income taxes are assumed to be calculated on net income net of royalties. Although this has not been the case since 1974, subsequent provincial tax measures have attempted to restore corporate taxes, as a proportion of net income, to pre-1974 levels. The capital cost allowance is taken here as 20 percent, following Brandie et al. (1982). Coal royalties were determined as 5 percent of the gross revenue requirements for independently operating mines equivalent in size to those used in the analysis (Alberta Energy and Natural Resources, 1976). Royalty calculations are presented in Appendix 1.

The remaining parameter to be specified is the required after-tax rate of return which is used as the discount rate (since taxes are netted out). As in the social evaluation, no single value is employed; rather, three values representing a broad range are used. The base or median value is taken to be 10.2 percent. This roughly equals the desired rate of 10.5 percent for the Alsands Project (Mariash, pers. comm.). A lower bound rate of 7.5 percent is

Table 5-2 First Year Market Values for Net Hydrocarbon Output ($ MM 1982)

	Case 1	Case 2	Case 3	Case 4
Syncrude	722.06	722.06	722.06	722.06
Butane	11.22	11.22	11.22	11.22
Natural Gas	-131.49	-131.49	-	82.24
Total	601.79	601.79	733.28	815.52

used, based on Brandie et al., who state that it is "typical of traditional rates of return in Canadian industry". (Brandie et al., 1982, 159). For an upper bound, 15 percent is suggested by Feick and McConaghy (1976) in their analysis of the private costs of various hydrocarbon energy sources.

5.4 Results

Scenarios employed in the financial analysis are identical to those described in section 4.4.1 and used in the social evaluation. Briefly, these involve three sets of real 1991 oil prices: a constant real 1982 oil price and variations of plus and minus 15 percent. Construction and operating costs are also assumed to be constant in real terms or increase by plus or minus 15 percent, in line with oil prices. Additionally, a high capital cost scenario at 82 percent above base costs is examined. This follows from the Rand Cost growth study and is intended to reflect possible over-runs not apparent in the early stages of cost

estimation.

Results for the financial analysis are indicated in Tables 5-3 and 5-4. The overall showing for the private assessment appears less optimistic than results in the previous chapter. The range of required increments for the base capital scenario is 1.77 percent per year to 12.63 percent per year compared to .69 percent per year to 4.52 percent per year for the social evaluation. The ranking of price scenarios by required increments is identical to the social case; the high oil price scenario provides the lowest increments, the constant oil price scenario is second, and the low oil price scenario shows the highest required price changes. For discount rates, it would be expected that lower rates would produce more favorable results due to the dominating influence of capital costs and this is indeed the case here. The Rand cost growth scenario produces similar rankings by price scenario and discount rate to the base capital case except that values are generally 4 to 5 percent per year higher. Increments for Rand costs range from 6.28 percent per year to a very large 16.97 percent per year. This compares to a range in chapter 4 of 4.7 percent per year to 9.26 percent per year.

Results for individual liquefaction alternatives reveal different rankings in the financial analysis in comparison to results in the previous chapter. In addition, whereas the ranking of alternatives under a social valuation of inputs and outputs was constant throughout, this is not always true

Table 5-3 Annual Required Oil Price Increments for Four Liquefaction Cases Under Alternative Oil Price and Discount Rate Scenarios - Base Capital

Discount Rate	Case 1	Case 2	Case 3	Case 4
		(% change/yr)		
Base Capital / Constant Real Oil Price 1982-91				
7.5%	2.16	1.97	3.38	3.11
10.2%	5.08	5.18	6.52	6.15
15.0%	10.59	11.01	12.25	11.77
Base Capital / High Real 1991 Oil Price				
7.5%	1.99	1.77	3.21	2.94
10.2%	4.89	4.97	6.33	5.96
15.0%	10.15	10.55	11.82	11.34
Base Capital / Low Real 1991 Oil Price				
7.5%	2.49	2.34	3.73	3.44
10.2%	5.45	5.59	6.90	6.52
15.0%	10.99	11.42	12.63	12.15

Table 5-4 Annual Required Oil Price Increments for Four Liquefaction Cases Under Alternative Oil Price and Discount Rate Scenarios - Rand Capital

Discount Rate	Case 1	Case 2	Case 3	Case 4
		(% change/yr)		
Rand Cost Growth / Constant Real Oil Price 1982-91				
7.5%	6.43	6.68	7.74	7.37
10.2%	9.54	9.94	10.95	10.53
15.0%	15.16	15.70	16.65	16.19
Rand Cost Growth / High Real 1991 Oil Price				
7.5%	6.28	6.52	7.59	7.22
10.2%	9.37	9.76	10.78	10.37
15.0%	14.80	15.33	16.29	15.83
Rand Cost Growth / Low Real 1991 Oil Price				
7.5%	6.73	7.00	8.05	7.67
10.2%	9.86	10.27	11.27	10.85
15.0%	15.50	16.04	16.97	16.51

here. For base capital costs, the alternative providing the lowest required price increment changes from Case 1 to Case 2 as the rate of return increases from 7.5 percent to 10.2 percent. This is a result of the higher required return putting power generation in Case 2 at a disadvantage relative to purchase prices from the provincial grid. In the Rand cost scenario, Case 1 dominates Case 2 throughout, again due to a relative cost disadvantage. Clearly from a private perspective, no matter which discount rate or capital cost is used, the preferred route for hydrogen production is steam-reforming of natural gas.

Comparing Cases 2 and 3, we find the ranking reversed from the previous chapter. The lower natural gas price here gives Case 2 the relative cost advantage in assigning solid residue to power generation and fuel gas to hydrogen manufacture. Case 4, as in the social evaluation, still requires a lower annual increment for a zero present value of net revenue than Case 3, despite the lower market value of fuel gas sold.

In summary, annual required oil price increments for a financial or private analysis are somewhat higher than for the social perspective. The ranking of alternatives is not consistent and differs markedly from the previous chapter's results. For a private firm, the preferred route to produce hydrogen is reforming of natural gas. The desirability of power purchases as compared to on-site co-generation of power and steam differs with the required rate of return,

favoring the latter at the 7.5 percent discount rate only.

6. Implications of the Analysis

6.1 Introduction

Results from the previous chapter indicate the existence of a divergence between the public and private incentives to pursue coal liquefaction. The case for this market failure rests on differing specifications for prices and discount rates. This chapter seeks to identify the relative roles of prices and discount rates in creating market failure, as well as to discuss the social cost and policy implications of the existence of market failure. Under this latter category are a number of considerations: the magnitude of social losses from either refraining from developing coal liquefaction or from a wrong choice of process design, implications for research and development, the role of cost overruns, and the implications of alternative financing schemes.

6.2 The Case For Market Failure

Bator defines market failure as "the failure of a more or less idealized system of price-market institutions to sustain 'desirable' activities or to estop 'undesirable' activities" (Bator, 1958, 352). Based on this definition, it appears that market failure may exist in the market for non-conventional energy technologies, coal liquefaction in particular. This market failure would be manifested in two ways. First, private net returns from coal conversion appear

to be lower than social net returns. This is reflected in higher annual required increments in the price of oil for the private case. This leads to the observation that a coal liquefaction project could provide positive net social benefits yet not be undertaken by a private firm. Second, a private firm wishing to minimize the annual increase in revenues necessary to break even would not make a choice from the four alternatives examined which would be consistent with the social optimum.

The presence of these inconsistencies in the analysis arises from differences between specified oil and gas prices and from differences between specified discount rates. Isolating the differential impacts of pricing and discount rates is difficult since the alternative model specifications are not strictly comparable; the financial analysis requires after-tax cash flows while the social evaluation is presented gross-of-tax. One solution to this problem might have been to use a pre-tax rate of return for the financial analysis. Sugden and Williams point out:

> A firm that appraises projects by applying a discount rate of 6% to their net-of-tax outlays and receipts, when profits are taxed at a rate of 50%, is behaving as if it were conducting a cost-benefit analysis using a social discount rate of 12%. (Sugden and Williams, 1978, 212)

Unfortunately, this approach must be rejected since it is after-tax returns which motivate private investment behavior.

An alternative approach is proposed whereby social prices for oil and natural gas are employed in the financial

analysis model. This facilitates comparison of the two pricing alternatives as well as identification of the disparate impact of higher discount rates. Results of this undertaking, based on the scenarios used previously, are presented in Tables 6-1 and 6-2.

Examination of the required oil price increments in Tables 6-1 and 6-2 reveals that values for Cases 1 and 2, where hydrogen is produced from natural gas, are higher and values for Cases 3 and 4, where coal is gasified to produce hydrogen, are lower than those indicated where market prices were used (Tables 5-3 and 5-4). In fact, required oil price increments for Case 4 are sufficiently lower to make this alternative the preferred choice in each scenario. This would be consistent with the optimal social choice indicated in chapter 4. Tables 6-1 and 6-2 also show that required oil price increments for the preferred Case 4 alternative are much higher in magnitude than increments for Case 4 in the social evaluation. Increments here are much closer in magnitude to those for the preferred Case 2 from the financial analysis of the previous chapter.

From the above observations we can draw two conclusions. Since the preferred alternative using the financial analysis model switches to the preferred social choice where social rather than market prices are used, it is evident that pricing distortions would be responsible for an inappropriate design-mix selection by a private firm. Discount rates, however, have not been adjusted from

Table 6-1 Annual Required Oil Price Increments For Financial Analysis With Social Prices Under Alternative Oil Price and Discount Rate Scenarios - Base Capital

Discount Rate	Case 1	Case 2	Case 3	Case 4
		(% change/yr)		
Base Capital / Constant Real Oil Price 1982-91				
7.5%	3.31	3.12	2.67	1.60
10.2%	6.22	6.31	5.83	4.67
15.0%	11.69	12.09	11.59	10.35
Base Capital / High Real 1991 Oil Price				
7.5%	3.15	2.94	2.49	1.42
10.2%	6.03	6.11	5.63	4.46
15.0%	11.28	11.65	11.14	9.89
Base Capital / Low Real 1991 Oil Price				
7.5%	3.62	3.48	3.03	1.97
10.2%	6.57	6.70	6.22	5.07
15.0%	12.07	12.48	11.99	10.77

Table 6-2 Annual Required Oil Price Increments For Financial Analysis With Social Prices Under Alternative Oil Price and Discount Rate Scenarios - Rand Capital

Discount Rate	Case 1	Case 2	Case 3	Case 4
		(% change/yr)		
Rand Cost Growth / Constant Real Oil Price 1982-91				
7.5%	7.35	7.59	7.18	6.18
10.2%	10.44	10.82	10.40	9.36
15.0%	16.03	16.54	16.37	15.07
Rand Cost Growth / High Real 1991 Oil Price				
7.5%	7.21	7.43	7.02	6.69
10.2%	10.28	10.65	10.23	9.19
15.0%	15.68	16.19	15.76	14.69
Rand Cost Growth / Low Real 1991 Oil Price				
7.5%	7.64	7.90	7.49	6.49
10.2%	10.75	11.14	10.73	9.70
15.0%	16.35	16.87	16.45	15.41

financial analysis specifications and required increments for the preferred case, although it has switched, have also remained relatively high in magnitude. This suggests that the higher private discount rates would affect whether liquefaction would be undertaken at all, even though social profits may be forthcoming. Thus, we may conclude that discount rate differences, whether actually representing a distortion or not, would serve to dampen the overall rate of commercialization of a non-conventional energy technology such as coal liquefaction.

6.3 The Implications of Market Failure

If it is the case that market incentives to pursue coal liquefaction (or other non-conventional energy sources) are inappropriate, and this appears likely, this may have social cost and policy implications. This is especially true with regard to non-conventional energy as a result of the lengthy and costly research, development, and commercialization phase which precedes operation of a facility. Early committment to a particular technology and input-mix is virtually irreversible once project development is underway.

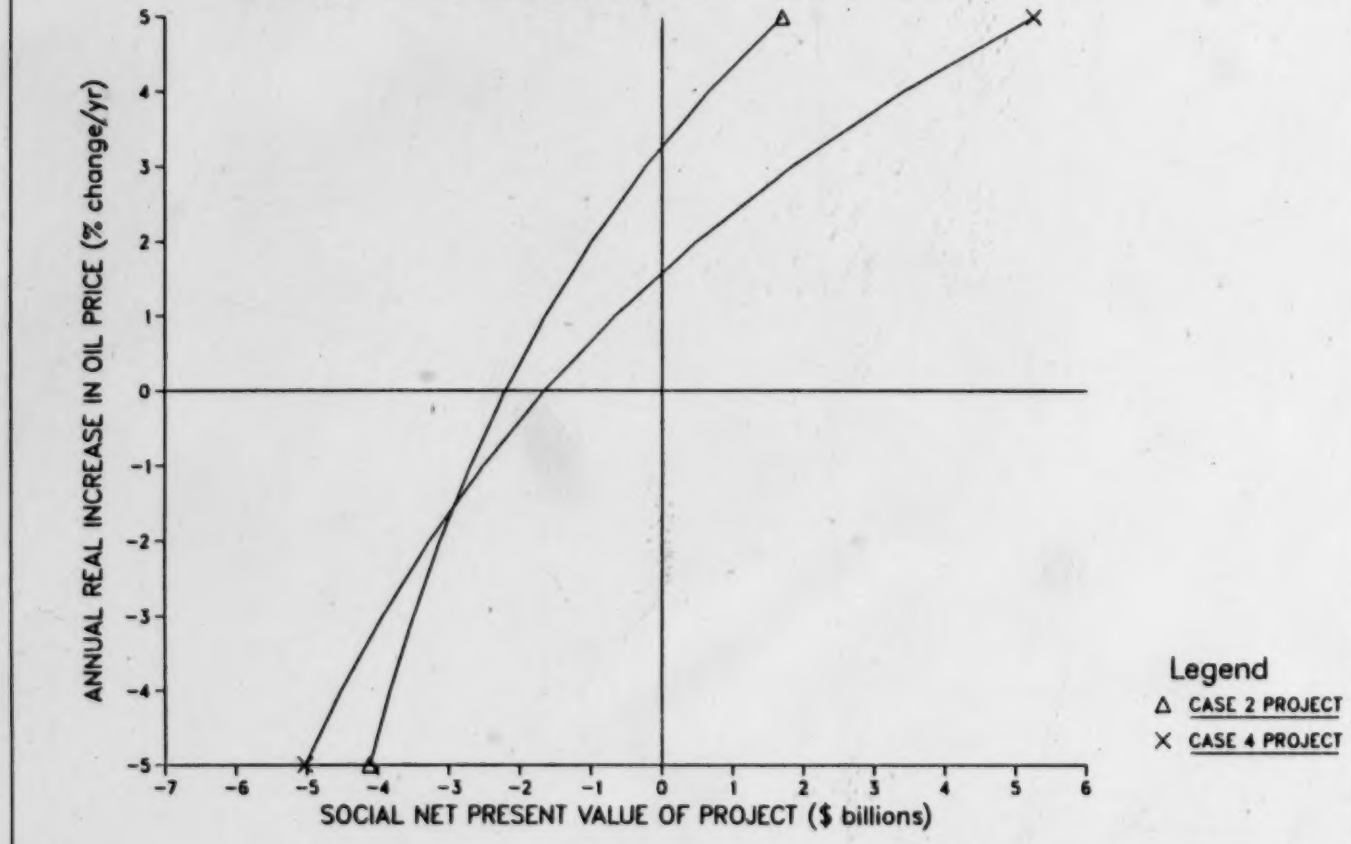
This discussion would appear academic except that there is some reason to believe that the process of development has already been initiated. Although immediate plans for construction of a liquefaction industry are not apparent, the funding of research such as the Algas study, as part of an ongoing phased process, suggests the possibility of

action in the future.

Implicit in the Algas study is the choice of natural gas as a hydrogen feedstock and on-site generation as a power source. Based on the evidence presented in this thesis, this approach to liquefaction may not represent the most desirable route from a social perspective. This argument, of course, assumes that liquefaction will meet the necessary market requirements and that a private firm will be willing to undertake it. Again, the results presented here suggest that these returns may not be forthcoming, despite an indication of potentially adequate social returns. We are left then with a situation wherein a private firm likely would not construct a liquefaction plant, even though it may be socially justified to do so, and that even if it did it would select a suboptimal design or input-mix.

The above observations would seem to indicate the possibility of social losses. But what would constitute these losses and how significant would these be? Some insight is provided in Figure 6-1. Here, social returns from liquefaction are plotted against a range of average annual real increases in the world oil price which might be forecast to occur over the project life. Three situations regarding commercialization of liquefaction are envisaged in Figure 6-1: construction of the Case 2 project as the privately-preferred undertaking, construction of the socially-optimal Case 4 project, and no project constructed at all, the continued importation case against which the

FIGURE 6-1
EFFICIENCY GAINS AND LOSSES FROM TWO COAL LIQUEFACTION CASES
FOR VARIOUS LEVELS OF OIL PRICE INFLATION



other two projects are assessed. Social returns, measured by project net present values, were calculated using base capital, social prices, the constant 1982-91 real oil price scenario, and a 7.5 percent discount rate.

The Case 2 project is taken as the private project to be considered since it represents the input-mix selected for further examination in the Algas study, and thus it is assumed to be the choice of a private firm under a regime of market prices. Despite this, Case 2 is not the highest return choice according to rate of return information in the Algas study, which is consistent with the findings in the previous chapter. It is possible that the prospect of simply throwing away the by-product residue, which occurs in the preferred Case 1 scenario, was expected to meet with regulatory disapproval from a resource utilization viewpoint.

Social losses will be expected to accrue if the preferred course of action at forecast price inflation is not pursued as a result of market failure. The magnitude of these social losses at each rate of price change will consist of the difference between net present values for the chosen route and the optimal route at that level of inflation. A perusal of Figure 6-1 indicates that the preferred route will change at the breakeven value for the Case 4 project. At forecast price inflation lower than this value, continued importation is optimal, whereas at forecast rates above the breakeven point, the Case 4 project should

be selected.

With the above observations in mind, social loss values arising from selected ranges of forecast price inflation can be determined. If, for example, forecast price inflation were in the order of 2 percent per year, and excessive private return requirements prevent construction of a liquefaction plant, the present value of social losses would total approximately $750 MM. If forecast inflation were closer to 4 percent, and private interests pursued the Case 2 project rather than the Case 4 project, social losses would be approximately $2.75 billion. An interesting and perhaps more realistic scenario would be a forecast price inflation rate of 2 percent with sufficient subsidies available (of a non-corrective nature) to induce private undertaking of the Case 2 project. Here, losses would total the $750 MM cited above plus another $1 billion, the amount social costs for the chosen private project would exceed the cost of continued importation.

Any conclusions arrived at concerning the possible attractiveness of coal conversion must be tempered by two observations. First, potential cost overruns could be significant. As Table 4-5 indicated, pursuit of liquefaction as an import alternative where Rand cost conditions apply may result in large social losses. Research geared towards clarifying cost relationships may help avoid this dilemna. Unfortunately, the price of this 'learning' may entail actual construction of a demonstration or full

commercial-size plant. Second, it has been assumed throughout the analysis that forecasts of oil price inflation, upon which a decision to construct a liquefaction plant may be based, will accurately predict actual circumstances during project operation. If forecasts are excessively optimistic, social losses may be incurred from construction of a liquefaction plant due to the highly capital-intensive nature of the investment.

The cost overrun problem may also have policy implications. Mention was made in chapter 2 of the loss of learning effects externalities where rapid development of a new technology prevents incorporation of this learning into successive plants. Should world oil market circumstances favor import substitution, policy makers would be wise to avoid the social losses that occurred from such hasty deployment in the nuclear power industry.

Additional implications arise from the nature of financing of the liquefaction alternatives examined. First, it was assumed that a liquefaction project would be a private undertaking. The result of this assumption was the choice of an opportunity cost 'price' of capital in the 10 percent range. Should a liquefaction project be either public or publicly-sponsored, a lower discount rate approximating the social time preference rate could be applied to capital as well as net returns. This approach was adopted by Wirick in his evaluation of the social production costs of syncrude from tar sands (Wirick, 1982). For the

liquefaction case, use of a 4 percent rate applied to both capital and net returns and the constant 1991 oil price scenario shows a required annual oil price increment of -2.66 percent for Case 4. Even if we assume Rand cost conditions to be true, the Case 4 alternative, under the same assumptions, shows a required increment of 1.41 percent per year. Obviously, a public sector liquefaction project could be feasible under most imaginable cost and oil price assumptions.

It was also assumed in the analysis that domestic capital markets would provide the funds for a liquefaction facility. As was pointed out in section 2.5.3, this may not necessarily occur and, in fact, has not been the case historically for large energy projects. It is certain, for example, that equity participants in Syncrude, as Canadian subsidiaries, tapped their American parent companies for funds. Applying social benefit-cost analysis to a foreign-financed energy project, however, entails a number of adjustments to the accounting framework.

Since it is probable that foreign funds invested in a domestic project would not have been employed in Canada had they not been used to finance the project under consideration, their opportunity cost to the domestic economy is zero (Little and Mirrlees, 1974). The after-tax return generated by this investment, however, does represent a real cost to the host country. Little and Mirrlees point out: "If it is all remitted abroad at once, it naturally all

counts as cost: these remittances are the cost of foreign investment, and the question is whether social returns to the country justify that cost." (Little and Mirrlees, 1974, 197-198).

The 'social returns' generated by a foreign investment are not so obvious, but once again Little and Mirrlees are helpful:

> ... in the case of the simplest foreign investment (no local participation and all profits remitted), ignoring unquantifiable externalities, the social profits of the host country in any year consists of (a) the direct tax paid, plus (b) the accounting value of the output minus the actual receipts, plus (c) the actual value of its expenditure minus the accounting value. (Little and Mirrlees, 1974, 127-128)

Benefit (b) described above represents the social net present value of the project in a conventional sense; for the liquefaction case, annual costs consisting of capital depreciation, net-of-tax returns remitted abroad, O&M charges, and taxes, are subtracted from the value of displaced oil imports. Social benefits under (c) would consist of any difference between the social and market values of the domestic resources employed in construction and operation of the project; throughout this thesis this difference has been assumed to equal zero.

The external effects of foreign financing should also be considered. Remittances of interest charges or after-tax profits represent payments abroad, offsetting the desired credit in the current account balance achieved by displacing imports. Any external balance of payments benefits which

would have been gained from reducing import purchases by an amount equal to remitted interest or profits are now lost and these foregone benefits would constitute a social cost of foreign financing. In addition to balance of payments effects, other social costs associated with foreign direct investment, some of which are discussed in section 2.5.3, may also be incurred. For further discussion of these issues, see Grubel (1977) and Kindleberger and Lindert (1978).

Using the evaluation methodology outlined earlier in this thesis, the capital flows, tax revenues, and required oil price increments arising from foreign financing of a liquefaction project can be determined. Burgess (1981) quotes an average real supply price of foreign capital of 4 percent, a rate at which the supply of foreign funds is assumed to be unlimited (Wirick, 1982). This rate is net-of-tax, again, since this is the real cost of the capital to the domestic economy (excluding the external implications of trans-border capital flows). If the Case 4 project was 100 percent foreign financed at 4 percent after-tax (constant 1982-91 real oil price scenario), 4 percent was also taken as the discount rate, and the relevant corporate income tax rate - which is identical to the rate applied to domestic firms - was applied, the pre-tax annual capital-related charge would be $611.62 MM. Of this amount, $286.79 MM would be principal, $172.16 MM would be remitted interest charges or profits, and $152.67

MM would be corporate tax payments. These figures include interest and taxes accumulated during construction.

In terms of the balance of payments impact of a domestically-financed project, Table 4-3 indicated that the Case 4 project under the constant 1982-91 real oil price scenario would initially displace $777.75 MM in oil imports (real 1982 dollars). In addition, the Case 4 scenario assumes that $158.44 MM in additional natural gas exports could be generated, bringing the total annual foreign exchange 'earnings' of the project to $936.19 MM, in first year prices. If the project is foreign-financed, the balance of payments impact will be reduced by $172.16 MM, the full amount of after-tax returns assumed to be remitted abroad, leaving the total exchange earnings of the project at $764.03 MM per year.

The capital-related charges calculated above also show that the deadweight loss from interest charges or profits would be almost completely offset by new corporate tax receipts. The difference, $19.49 MM, represents the average annual social returns in excess of all accounting costs (benefit (b) above), which must be generated by the project in order for a zero net present value to be attained. Based on a 4 percent social discount rate, the required increment in the social value of output from Case 4 to provide this zero present value would be -3.02 percent per year. This value is significantly less than the .84 percent indicated in Table 4-4 where domestic financing is assumed.

If a more realistic assumption is that the after-tax return to foreign capital, and thus the discount rate, would be closer to the 10.2 percent assumed in the financial analysis, and this is reflected in the market price applied to project output, the required increment would rise to 4.26 percent per year. This compares to an increment in the domestic-financed case, with use of a 10.2 percent discount rate, of 2.30 percent per year.

It should be noted that if the market price of output from a liquefaction plant is tied to the price of oil imports, a particular after-tax return to foreign investors cannot be guaranteed should the world oil price fall; and additionally, since the funds have no domestic opportunity cost, a low realized return to foreign funds will not incur social costs as long as it is offset by taxes plus the excess of oil import prices over the market price of output. Clearly, the desirability of foreign financing will depend crucially on the rates of return expected by foreign investors and whether these returns are assured by the market price of output.

The discussion presented in this chapter supports the conclusions that from a social perspective liquefaction may be more feasible than previously thought and that hydrogen from coal should be examined as an alternative to the natural gas feedstock case. Exceptions to these conclusions will be evident in the presence of the following: significant cost overruns, excessively optimistic forecasts

of oil price inflation, or high rates of return guaranteed on foreign-invested capital; in all cases, ambitious development of liquefaction may lead to social losses. In addition, it will be necessary to assess liquefaction against other import substitutes and hydrogen from coal against hydrogen from alternative feedstocks. In the latter case, coal gasification could be assessed against exotic possibilities such as use of off-peak hydro power for hydrogen production (electrolysis), once cost information becomes available.

7. Observations and Conclusions

7.1 Observations

This thesis has examined the potential for oil import substitution from a non-conventional energy source such as coal liquefaction. The analysis focused on the prospects for this technology from a social perspective, as well as the potential for a misallocation of resources due to a divergence between social and private profitability. In the course of the study a number of points were noted which relate to an economic evaluation of undertaking liquefaction, but could not necessarily be reflected in the quantitative analysis. These observations are summarized below.

1. Schmalensee (1980) makes the valid point that the presence of market distortions in the market for non-conventional energy does not imply that corrective action, such as subsidies, should be taken. Production in many industries demonstrates a divergence between social and private optima and there exists a tradeoff, in terms of correcting for this, between what is theoretically desirable and what is administratively possible. In order for non-conventional energy projects to warrant subsidization, further justification, such as the existence of unique distortions or circumstances, would be necessary.
2. In the case of most non-conventional energy-related

market distortions, alternatives besides adjusting project costs and benefits exist for corrective action. Examples include: appropriately drawn up agreements to circumvent uncertainty over future regulation, a strategic stockpile of petroleum along with an administered devaluation to alleviate both security of supply problems and concern over the balance of payments effects of an increasing import bill, and alternative regional investment expenditures which might satisfy regional employment and income enhancement objectives in a more satisfactory manner. Where these alternatives are preferred, whether on efficiency or equity grounds, there is little justification for attaching such benefits to a non-conventional energy project. Subsidies and tariffs, as a result, are less likely to be warranted.

3. Even though some legitimate market distortions may arise from import substitution and require corrective action (pricing, for example), these will be at least partially offset by certain extramarket costs arising from large expensive energy projects. For example, continued importation of petroleum clearly avoids the plethora of environmental problems associated with tar sands or liquefaction plants. In addition, the capital-intensive and costly nature of these plants means that significant reductions in import prices, once the project is built, could precipitate social losses from import

substitution, even though returns may still cover short-run marginal costs.

4. Uncertainty over cost relationships in large energy projects has led to significant overruns in final costs. Unfortunately, outside of predictive models such as the Rand cost growth model, these relationships can likely be clarified only through project construction. Should such construction occur, industry development should be phased so as to take advantage of this information, whether technical or cost related, when successive plants are built.
5. Non-conventional energy projects have generally been visualized as privately-sponsored projects. This implies an opportunity cost of capital approach to investment funds, although from a social perspective, net project returns can be discounted at the social time preference rate. Such private projects require much higher rates of return due to tax and risk factors, and this results in fewer projects being undertaken. If such a project were public or publicly-sponsored, discount rates and required rates of return could be much lower. This would effectively reduce the social production costs of project output and presumably increase the optimal number of projects.
6. If a liquefaction plant is wholly or partially funded from foreign sources, there will be a number of implications. The true cost of this capital to the

Canadian economy is the net-of-tax return, which flows out of the country, since the tax portion represents new domestic earnings retained and the capital itself has no domestic opportunity cost. Calculations for a liquefaction project indicate that the remitted portion of earnings is largely offset by the new government revenue provided from taxes. Whether foreign financing will generate greater or fewer net benefits than the domestic financed case was indicated to depend crucially on the spread between returns to foreign direct investment and domestic opportunity costs, and whether foreign returns would be guaranteed when the market price of project output is set. The issue becomes complicated further once the external effects of capital flows are considered.

7. Social assessment of coal liquefaction must address the issue of coal opportunity costs. If coal destined for conversion could generate social profits elsewhere, then foregoing these must be included as a legitimate cost of coal for liquefaction. Indications are that sufficient quantities of coal exist for conversion without causing a shortfall elsewhere, particularly in the thermal power industry. On the other hand, if new power plants must make use of higher cost coal, thus increasing delivered power costs, this cost must be offset by liquefaction net benefits. Where optional uses are available to private holders of coal, this cost would be

internalized. This problem is unlikely to arise given current power demand forecasts, however, until after 2005.

8. Production of large quantities of carbon dioxide from liquefaction also presents problems for social evaluation. Where this gas is freely dissipated into the air, long run social costs are incurred due to climatic impacts such as the 'greenhouse effect'. On the other hand, carbon dioxide may have a scarcity value in use for enhanced oil recovery. This latter benefit would only accrue where alternative sources of the gas are more costly or non-existent. Where this benefit does occur, it may serve to partially or fully offset coal opportunity costs.

7.2 Conclusions

The quantitative analysis contained in this thesis involved the private and social evaluations of four liquefaction projects. The alternatives varied with regard to hydrogen manufacture (steam-reforming of natural gas or gasification of coal) and power source (purchased or various on-site generation designs). The private and social evaluations of each project differ in terms of the specification of hydrocarbon prices and discount rates. Rather than using project net present value for comparison purposes, this was set equal to zero and the real annual increment in world oil prices which satisfied the net

present value equation was calculated. This was meant to exclude the uncertainty of future oil price inflation. Thus, results are not contingent on any particular price scenario occurring during the operating phase of the project.

The projects examined were based on an engineering cost study and other data sources, and were assumed to come on-stream in 1991. In order to account for potential changes in oil prices and provincial economic activity between 1982 and 1991, three scenarios were developed for the real 1991 oil price. As well, the possibility of cost overruns was taken into account by including a scenario with capital costs at 82 percent above their base case values. This value was determined through use of the predictive Rand cost growth model. Results and implications from the analysis are summarized below.

1. Results of the analysis ranged widely and were sensitive to the choice of discount rate and capital cost scenario. The most promising case, which makes use of coal as a hydrogen source and on-site coal-fired generation for power, was evaluated at a 4 percent discount rate, high 1991 oil price, and base capital costs, and showed a required real oil price increment of .69 percent per year (over the project life). Based on current and historical projections, liquefaction would appear to have some potential. Where Rand costs apply, a required increment 4 to 5 percent per year higher could be expected, effectively removing all prospects for

social profits.

2. A market or financial analysis of the same liquefaction projects yielded very different results from the social evaluation. Annual required increments were higher and the preferred input-mix switched to one where natural gas is the hydrogen feedstock and power is purchased. The findings reflected a lower syncrude price, a lower natural gas price, and higher required rates of return.
3. The perceived divergence between the social and market assessments was taken to indicate the presence of market failure. Although this is strictly true for price distortions, it is unclear whether a divergence between social and private discount rates actually represents a true distortion. A simple test showed that the price distortion was responsible for the inappropriate private choice of inputs while the higher private discount rate led to lower profitability for the private project.
4. The major implication of the analysis is that market failure could lead to social costs where forecast oil price inflation is adequate for development of a liquefaction industry. If real oil price inflation is expected to be in excess of 1.5 to 2 percent per year, construction of either no liquefaction plants or plants with a suboptimal design could lead to social losses in the billions of dollars. Indications are that current private commercialization research is focusing on an inappropriate input-mix and should be reassessed.

Despite this, examination of coal liquefaction, and in particular a hydrogen-from-coal based design, is warranted in the future assessment of oil import options for Canada.

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APPENDIX 1: Coal Cost Adjustment

Section 3.3.2 outlined a method for adjusting coal mine costs to account for economies of scale. Since these effects are pronounced in the strip mining of coal, those liquefaction cases which make use of coal gasification for hydrogen or coal-fired power production could be expected to have lower unit mine costs than those liquefaction cases which do not need additional coal for these purposes. If a marginal cost curve existed for western plains coal, information on unit costs could be easily deduced. Unfortunately, with the absence of such a curve an alternative approach was necessary. The approach selected was the use of econometric cost functions devised by Zimmerman (1981) for western American sub-bituminous coal. Using physical and geological data for the required mines in this study, costs for a specified data mine, and the above mentioned cost functions, costs for the required mines were derived. Since Cases 1 and 2 required volumes of coal similar to the data mine, no adjustments for these two cases were made. Adjustments made to Cases 3 and 4 are detailed in the following sections.

i) predicted values

Zimmerman's equations are presented in the following additive form:

$$K_i = 3{,}746{,}000 + 394.117\,(RQ)^{.8123}\,N^{.507} + .282Q$$

$$K_d = 2{,}628{,}000 + 7.486\,(RQ)^{.8123}\,N^{.507} + .144Q$$

$$O\&M = 387{,}000 + 32.182\,(RQ)^{.8123}\,N^{.507} + .271Q$$

where:

K_i = initial capital cost ($ MM)
K_d = deferred capital cost ($ MM)
O&M = operations and maintenance cost ($ MM/yr)
R = average strip ratio (cu yd/T)
Q = annual output of coal (MM T/yr)
N = number of draglines

Physical data for the three mines is the following:

Coal Mine Physical Data

	R	Q	N
data mine	8.59	9.12	6
Case 3	8.59	11.90	6
Case 4	8.59	13.80	6

Inserting these values into the above equations yields the following predicted values:

Coal Mine Predicted Cost Values

	K_i	K_d	O&M
data mine	72.94	5.20	8.30
Case 3	85.50	5.83	10.00
Case 4	93.57	6.25	11.14

ii) cost adjustment ratios

In order to adjust data mine costs to give estimates for Cases 3 and 4, ratios were formulated with the predicted data mine value as denominator and the appropriate Case 3 or Case 4 predicted cost value as numerator:

Coal Mine Cost Adjustment Ratios

	K_i	K_d	O&M
Case 3	85.50/72.94=1.172	5.83/5.20=1.121	10.00/8.30=1.205
Case 4	93.57/72.94=1.283	6.25/5.20=1.202	11.14/8.30=1.342

iii) adjusted final costs

The above ratios were used to multiply data mine costs to get adjusted costs for Cases 3 and 4 (Montreal Engineering, 1978).

Total capital costs are the sum of adjusted initial and deferred costs. Deferred capital for the data mine was averaged over the 25 year project life and discounted to the present at 10.2 percent. Final operations and maintenance costs include municipal taxes and insurance at 2 percent of initial capital. This approach results in the following final values for capital and annual charges, which were then entered in Table 3-5 of chapter 3:

Coal Mine Final Costs ($ MM 1982)

	data mine (Cases 1 and 2)	Case 3	Case 4
Initial capital	283	332	363
Deferred capital	79	89	95
TOTAL	362	421	458
O&M	37.02	44.61	49.68
Taxes and Insurance	5.66	6.64	7.27
TOTAL	42.68	51.25	56.95

For the financial analysis contained in chapter 5, the calculation of coal royalties was necessary. Since the

royalty is calculated at 5 percent of gross revenue, the gross revenue requirements for each mine included here were determined. This meant amortizing capital at an assumed pre-tax rate of return of 13.2 percent, made up of a 10.2 percent after-tax component and a 3 percent net corporate income tax allowance (Helliwell and May, 1976). To the capital charge was added the relevant O&M cost from above. Calculated royalties, based on 5 percent of capital charges plus O&M, were: $4.64 MM per year for Cases 1 and 2, $5.47 MM per year for Case 3, and $6.01 MM per year for Case 4.

APPENDIX 2: Detailed Cost Estimates

In addition to the two liquefaction cases outlined in the Algas Study, two alternative cases were assessed. These differed from the Algas cases primarily in that hydrogen was produced from coal rather than natural gas. As a result of this difference, the plant's material balance was altered and adjustments to a number of process areas were required. This involved capital and operating cost changes for both Case 3 and Case 4. The process areas affected, in addition to hydrogen production, were: power, coal preparation, ash handling and disposal, coal handling and the sulphur plant.

Capital Costs for Cases 1 and 2 were updated directly from the Algas Study and totals are contained in Table 3-5. In order to make consistent estimates for Cases 3 and 4, costs for process areas affected by the change in hydrogen production were netted out of the Case 2 estimate, leaving a residual 'base' cost. Process area costs were then re-estimated, based on Case 3 and Case 4 parameters, and added to the 'base' cost to give a total construction value. The 'base' cost is derived as follows:

Derivation of Base Plant Cost ($ MM 1982)

Case 2 total cost	4200
Hydrogen plant	-954
Power and Steam Plant	-573
Sulfur Plant	-22
Ash Handling and Disposal	-11
Coal handling	-88
Base Cost	2552

The following passages describe the re-estimates for Cases 3 and 4. All values are summarized in a table at the end of the section.

i) hydrogen plant

United States data was obtained for a coal-to-hydrogen plant and contained a cost for a 351.7 MM SCFD process unit at an eastern Kentucky location, expressed in mid-1975 prices (United States Department of Commerce, 1978). In order to convert this to a 1982 total cost for a 770 MM SCFD plant at an Alberta location, a number of adjustments were necessary. Inflation was accounted for by using the Statistics Canada construction cost index for Chemical and Petrochemical Plants (Statistics Canada, 1983a). Size was adjusted using a .8 factor for economies of scale (Dynawest, 1983). All indirect cost factors were taken from the Algas study. Adjustment factors are summarized below:

Adjustment Factors for Capital Cost Estimates

Inflation	X 1.83
Size $(770/352)^{.8}$	X 1.87
Location	X 1.46
Transport and Import Duty	X 1.25
Piping, Instrumentation, Electrical, and Process Structures	X 1.93
Offsite Piping, Site Development and Administration Buildings	X 1.30
Engineering and Construction	X 1.35
Contingency	X 1.20
TOTAL	X 24.31

Applying this value to the source cost of $118 MM gave a

final cost of about $2870 MM. This value, when compared to the capital cost for the steam methane reforming plant, shows a ratio of about 3 to 1. This is identical to results obtained by Corneil (1977) in a study of the production economics for hydrogen to the year 2000.

ii) power plant

For Case 3, a combined-cycle power plant was integrated into the liquefaction complex. Use of coal gasification for hydrogen allowed by-product fuel gas to be used as the power plant feedstock. Based on International Energy Agency (IEA) data, the cost of a combined-cycle plant is approximately 46 percent of the cost of an equivalent coal-fired plant (Hemming et al., 1979). The coal plant cost used here is from Keephills and totals $743/kW in 1982 dollars (EUPC, 1983). This implies a combined-cycle cost of $342/kW. Multiplying this by the 600,000 kW of capacity gives a total cost of $205 MM.

The Case 4 power plant was assumed to be similar to the Case 2 solid residue-fired plant, described in the Algas study. Since the power required was only half of the Case 2 output, costs were scaled-down using a .8 factor on the power generation unit and a .6 factor on the flue gas desulpherization unit. The reason for the higher factor on the power unit was the lower expected economies of scale due to the existence of two parallel trains in the source estimate, one of which would be removed for Case 4

requirements; thus, no change in boiler capacity would occur. The resulting total cost was $333 MM, compared to a Case 2 value of $575 MM.

iii) other process areas

Cost re-estimates were necessary for several other process areas, including: sulfur plant, coal handling, and ash handling and disposal. Adjustments in each case were made by first determining the new capacity required and then adjusting costs with a .6 scale factor. Final values are indicated below:

Adjusted Process Area Capital Costs ($ MM 1982)

	Case 2	Case 3	Case 4
Base Cost	2552	2552	2552
Hydrogen Plant	954	2870	2870
Power Plant	573	205	333
Sulfur Plant	22	112	112
Coal Handling	88	100	109
Ash Handling and Disposal	11	64	64
TOTAL	4200	5903	6040

Adjustments to plant operating costs were based on information provided in the Algas study, suitably updated where necessary. As in most engineering level studies, operating costs are derived from factors which are applied to certain project parameters. These factors, inclusive of by-product values, are listed below:

O&M Cost Factors and By-Product Values

Labor	$30,500/man-yr.
Maintenance	1% of capital (excluding contingency)
Contract Maintenance	$2 MM/yr
Insurance/Taxes	2% of capital (excluding contingency)
Power purchased	$26/MW-hr
Power sold	$21/MW-hr
By-products:	
Sulfur	$50/t
Ammonia	$385/t
Soda Ash	$75/t

Applying these values to the material balance and capital cost information in Table 3-5 gives the operating cost totals also provided in that table.

APPENDIX 3: Rand Cost Growth Model

In order to account for the possibility of large capital cost overruns, analysis from the Rand cost growth study was used for predictive purposes. In the Rand study, Merrow et al.(1981) constructed a regression equation using a number of independent project and technology specific variables with the ratio of estimated to final costs as the dependent variable. Although their sample of 44 energy processing plants does not include a liquefaction plant, it does include several tar sand and oil shale projects. For purposes here, and based on their recommendations, it is assumed the analysis would apply equally to a coal liquefaction plant. Their equation is:

$$CG = 1.12196 - .00297P - .02125IM - .01137C + .00111IN - .04011D_1PD - .06361D_2PD$$

$$R^2 = .83 \qquad SE = .83$$

where:

CG(Cost Growth)	= ratio of estimated to actual costs, excluding external cost factors.
P(Percent New)	= percent of estimate incorporating technology unproven in commercial use.
IM(Impurities)	= assessment by industry process engineers of difficulties with process impurities encountered during development.
C(Complexity)	= block count of all process steps in plant.
IN(Inclusiveness)	= percent of cost items included, measuring completeness of estimate.

PD(Project Definition) = levels of site specific information and engineering included in estimate; $D_1 = 1$, $D_2 = 0$ if process proven at precommercial or commercial stage, $D_1 = 0$, $D_2 = 1$ if process in R and D stage.

For the liquefaction plant under consideration here, variable values were determined in consultation with engineering staff at Algas Resources. The values settled on were:

PERCENT NEW = 40
IMPURITIES = 4
COMPLEXITY = 10
INCLUSIVENESS = 100
PROJECT DEFINITION = 5.75
$D_1 = 0$, $D_2 = 1$

Inserting these values in the above equation yields a cost growth figure of .549. Inverting this results in a value of 1.82, suggesting an 82 percent increase in actual costs over initial estimates for the project in question. This value was used to inflate the capital costs presented in Appendix 2 and chapter 3, to allow consideration of a Rand cost growth scenario in the analysis.